Attachment A - Functional Deferral 6

Adjusting Dispatch Instructions to the Defined Metering Point

1. Background

In March 2000, the Technical Panel was informed that certain functionalities would be deferred beyond the November 2000 market commencement date.

Functional Deferral-06 (FD-06), Adjust Dispatch Instructions to Defined Metering Point (DMP) was presented as follows:

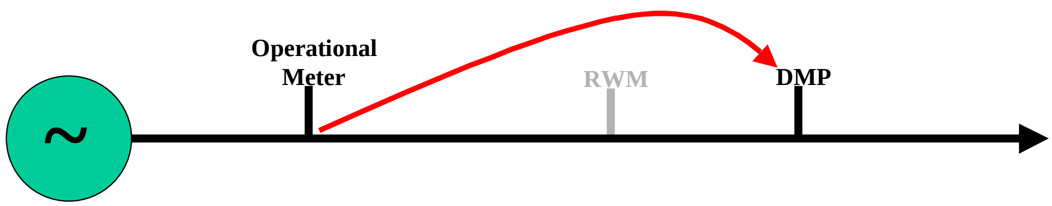
Deferral	There will be no mapping of operational meter data to the corresponding revenue metering point. (The Congestion Management Settlement Credit requires such a transformation because it defines the dispatch instruction as occurring at the point of sale).
Major Implication	Participants will be underpaid for both constrained on and off payments. Losses could be in the range of 0 to 4% of output.
Current Assessment	***Current thinking shows that both over and under payments to dispatchable facilities can occur.***
TP Comments (March 7, 2000, TP-36)	Acceptable. Staff should examine if something can be done to mitigate the impact of the high loss situations. The Panel noted that the losses could be significantly larger when looked at as a proportion of the CMSC.

Implementing this functionality:

- will require mapping of the operational meter data to the point of sale; and
- will impact CMSC as the dispatch instruction is currently treated as occurring at the operational meter.

2. What Will Change?

What will change?



FUTURE

•Dispatch Instructions (DI) and Market Schedules (MS) are issued to the Operational Meter for realtime dispatch **BUT are converted to the DMP prior to settlements**.

•Dispatch and dispatch compliance is measured at the Operational meter.

•Settlement (CMSC) uses the DI and MS referenced to the **defined metering point.**

•Actual output and energy payment is based on the AQEI which is the RWM actual converted to the DMP using a correlation factor.

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3. Market Rules

Market rules in chapter 9 were amended for Baseline 3.1 by MDI-103 subs 30 to 34; and were approved by the IMO Board on August 18, 2000. The market rules now read as follows:

3.1.4A For the purposes of sections 3.1.3, 3.1.4 and 3.5.2, “location m” in respect of *market participant* k shall mean:

3.1.4A.1 until the date that is the last day of the ninth calendar month following the *market commencement date*, calculated from the first day of the calendar month immediately following the month in which the *market commencement date* occurs,

the location of:

a. the relevant *meter* used by *market participant* k to meet the monitoring requirements of section 7.3, 7.4, 7.5 or 7.6, as the case may be, of Chapter 4 in respect of *registered facility* k/m, where such requirements apply in respect of *registered facility* k/m; or

b. the *RWM* for *registered facility* k/m, where the monitoring requirements of section 7.3, 7.4, 7.5 or 7.6, as the case may be, of Chapter 4 do not apply in respect of *registered facility* k/m; and

3.1.4A.2 after the date referred to in section 3.1.4A.1, the *RWM* for *registered facility* k/m.

4. Exemption Application

An exemption to chapter 9, section 3.1.4A was granted to the IMO for the period of March 1 to August 1, 2003. A condition of the exemption was to:

- provide a detailed study to identify and better understand the implications on the marketplace;
- identify and understand the impacts associated with implementing the functionality (Market Participants and the IMO);
- determine whether or not the implementation of this functionality will materially benefit the marketplace; and
- stakeholder recommendations with Market Participants.

5. Areas of Impact/Assessment

5.1 IMO Costs to meet the Intent of FD-06

Actual implementation details are not finalized but there were two general approaches reviewed in the study. The options reviewed were:

1. "Correlation Factor" approach; and
2. "Simple Loss Factor" approach.

5.1.1 Derive a correlation factor between the operational and revenue meters (Option A)

This alternative assumes that it is relevant to deal with the accuracy difference between the operational meter and the revenue meter. Thus the identity of the operational meter is of interest.

The approach consists of deriving a correlation factor between the operational meter and the revenue meter. This factor includes the accuracy difference, losses (transformer and secondary wiring), and loads tapped off. However, each of the components of the factor cannot be separated out.

In order to determine and manage these correlation factors, it is necessary to perform the following:

- The market participant has to register the operational meter with the IMO.

- The market participant has to determine the correlation factor and submit the information to the IMO.
- The IMO has to complete the registration.
- The IMO and the Participant have to perform annual review.

At least a year of data is necessary to establish the correlation factor. It is assumed the participant has the data on hand to perform this calculation. It is also assumed that there is one-to-one correlation between operational meter and revenue meter. Complexities of certain involved totalization cases and certain cases of disaggregation may complicate the solution.

Assume that there will be 300 operational meters that will require this process. Also, assume that the data to establish the correlation factors is available. The cost of implementation is as follows:

- Registration of a meter will cost $2,000, split evenly between the participant and the IMO. 300 meters will require a total of $600,000. The registration cost is much less than that of a revenue meter because there is no need to determine the delivery point, establish losses, set up and test.
- The participant establishes the correlation factor. It is estimated this will take $50,000, assuming the bulk of the meters are with OPG and with data already stored in database.
- IMO will have to significantly enhance existing market rules and manuals. It is estimated this will take $50,000.

On an ongoing basis, the following operational cost will be incurred:

- The correlation factor will need to be updated, at a cost $50,000 per year.
- It is assumed that operational meter trouble handling will be done by Operations as it is today. The Settlements' Meter Trouble Reporting System need not be used.

In summary, the total implementation cost for this alternative is $700,000 split evenly between the IMO and MPs. The total operational cost is $50,000 per year for the Market.

Based on previous experience defining the RWM/Defined Meter Point (DMP) relationship this activity could take upwards of 2 years.

5.1.2 Derive the losses between the operational meter and the DMP (Option B)

This alternative is only interested in reflecting the operational meter to the DMP. Typically, the operational meter is located on the low voltage side. Between the meter and the DMP is a transformer. It is also possible that there is load tapped off. The identity of the operational meter is of no interest.

The operational meter will not be registered with the IMO. Losses in the secondary wiring of the operational meter are of no interest. Losses of the transformer will be determined using transformer data. Installations with loads between the operational meter and the RWM would need further consideration. The Market Participant will be required to report future changes to the IMO.

Assume that there will be 300 operational meters that will require this process. The implementation cost consists of:

- The cost of loss and load determination at $1,000 per meter.
- The cost of revising the Market Rules at $20,000.

Thus, the total implementation cost is $320,000. The operational cost is relatively small and is ignored.

5.2 Market Costs to Meet the Intent of FD–06

The IMO has initiated discussions with our vendor with regard to the system changes required to meet the requirements of FD-06. Based on the understanding of having to move both the constrained and unconstrained schedules to the revenue meter point the IMO costs (vendor system changes to both DSO and Settlements, testing and documentation) will total about $350kCAN.

The IMO will need to modify the DSO constrained and unconstrained schedules by specific factors or sets of factors and post these revised schedules on our web site. This will all be done the day after the dispatch day. We will then also have to pass these on to our settlement systems such that they use these revised constrained and unconstrained schedules as opposed to the ones they use now. The IMO will not be revising the demand calculations used for the development of MCP and HOEP prices.

The $350,000 consists of the VCR118_2a which costs about $157kUSD @1.5 = $235kCAN. Including 15% for testing and documentation increases this to $270kCAN. The final $80kCAN would be for changes to PLC and CRS, posting in new reports the new dispatch instructions for the constrained and unconstrained schedules for energy and operating reserve. Also included would be the work required to load the correlation factors into the MIS databases and make changes to SDR. The vendor has stated it will take up to 18 weeks (4 ½ months) for them to deliver their software. Testing and documentation time will be on top of this and we will require to work this into our Release management dates, as this is will be a very impactive market facing change.

Only market participants that are dispatchable would be affected by this change. The costs for the market participants to make these changes will vary from participant to participant. However, for the dispatchable market participants who need to make changes they will most likely need to change their data acquisition tools to obtain the IMO's revised constrained and unconstrained schedules from the IMO's web site. As well they will have to change their settlement tools to point to these new sets of data.

At the time of publication the IMO has not determined the costs to modify the offers to accurately calculate the CMSC. These changes are necessary to ensure that when the CMSC MW adjustment crosses price laminations that the CMSC is calculated at the proper offer price. As an estimate however a 25% increase to the VCR cost can be used and results in a total cost $340k.

5.3 Meter Evolution

Some new meter installations have "hybrid" meters with the RWM and operational meter at the same source. If this trend continues then this functionality is no longer required as the issue of differences in loses and payments would disappear. Market Rule changes would be required.

Although a market participant has started down the road of using PML meters as a source for both revenue data and real time telemetry, issues such as divergent standards may impede this evolution. The rules require an RTU problem on the operational meter side to be corrected in 24/48 hours depending on how impactive the facility is (chapter 4). RWM errors due to the validate, edit & estimate (VEE) process have to be resolved within 6 days. When using a combined meter if the problem is related to anything on the MSP administered part of the box (Revenue meter), the point could be down for up to 6 days (chapter 6).

The IMO's difference in requirements between the Operational Metered side of the house 24/48 hrs and the Revenue meter side of the hours up to 6 days could lead to a significantly increased contracting cost with the participants MSP that may overwhelm the savings of the 1 meter approach. This could be overcome if the MP has backup telemetry, but most don't at this point. The participant who has been installing the single PML as a source for both revenue data and real time telemetry, are looking at backing away from this type of arrangement.

5.4 Compliance Impact

The process for assessing non-compliance with dispatch instructions currently uses the operational meter quantity, comparing this to the dispatch instructions. It is anticipated that an adjustment to the dispatch instruction would create minimal problems for this process.

If the proposed change of adjusting schedules to the DMP would provide two dispatch instructions, one at the DMP and one at the Operational metering location (the current situation), this should not cause a problem for the IMO non-compliance assessment. Two instructions would in fact represent a back up, if the operational meter was not functioning, the settlement revenue meter quantity could be compared with the adjusted dispatch instruction.

If the proposed change leads to only a single instruction at the DMP replacing the instruction at the operational meter point, this would necessitate using the revenue meter data without the alternative of a backup.

A change to a single instruction at the DMP would cause significant problems, mainly because plant operators do not have an “energy” readout on the panel to control to, only an instantaneous MW. Also, with the current rules we cannot enforce compliance to a ramp, only to the MW at the end of the interval. This is a fundamental change, we would be enforcing compliance against a parameter (energy) that was not used in the original scheduling of the resource (DSO use of an instantaneous MW).

Rule changes to allow this would not pose a significant cost.

Timing is not an issue for MACD, but would be for the control room who do not have access to revenue meter data in real time. Since RWMs and operational meters can vary the most during the time periods when the CRO has the greatest concern for compliance, this will not be acceptable.

5.5 CMSC Evaluation

Modifying schedules to reflect the DMP primarily affects market payments through the CMSC calculation. This section attempts to quantify the impact of the potential rule change on these payments.

OR payments, which are based on scheduled quantities would change in terms of how much is assessed as being provided by each facility. However, since the total quantity required would remain constant, the net payment by the market to OR providers would not change.

Congestion payments for energy are related to the operating profits associated with the market schedule (MQSI), the dispatch schedule (DQSI) and the actual energy injection or withdrawal (AQEI or AQEW). There are also congestion payments for Operating Reserve related to comparable operating reserve quantities.

5.5.1 CMSC Payments

In the following analysis, we focus only on the bulk of payments that may be affected by the deferral. To this end, consider congestion payment data in the recent Discussion Paper used by the Market Surveillance Panel (MSP) for their CMSC consultation. Table 1 reports CMSC payments from May to December 2002, showing positive and negative CMSC for energy, and the net payments for operating reserve.

Table 1: CMSC Payments for Energy and Operating Reserve - May to December 2002

CMSC Payments ($million)	Positive CMSC payments for energy		Negative CMSC payments for energy		Total CMSC for Operating Reserve
	Constrained on	Constrained off	Constrained on	Constrained off	
Fossil	9.5	25.4	-0.9	-0.0	-0.3
Hydroelectric	22.9	18.4	-1.9	-0.2	2.2
Nuclear	0.2	3.6	-2.1	-	-
Imports	83.6	15.8	-4.6	-34.3	0.0
Dispatchable load	0.1	5.7	-0.0	-	0.1
Exports	0.3	10.5	-0.2	-0.4	0.0
TOTAL	**116.7**	**79.3**	**-9.7**	**-34.9**	**2.1**

Import and export CMSC would not be affected by a rule change in the sections in question. The bulk of the remaining payments are to fossil and hydroelectric generation, totalling $29.6 M (net positive and negative) for constrained on operation and $43.6 M for constrained off operation. Net payments to nuclear generators and dispatchable load are $1.7 M and $5.8 respectively; because of their relatively low magnitude and other complicating factors, these are not considered in the impact calculations below.[1] CMSC for OR is small, and is unlikely to be sensitive to the DMP adjustment.

5.5.2 MW Adjustment

Schedule quantities are currently viewed as consistent with the operational meter point. Any adjustment of the schedule quantities to the DMP would thus reflect the difference between the operational meter point and the DMP, where settlement quantities are calculated (as derived from revenue meter data). In order to assess what the adjustment may be, we can therefore consider the differences in readings between the two types of meters.

These difference were addressed in the earlier assessment related to preliminary and final pricing[2] In that analysis, four key areas of price variation were identified that may exist between the provisional, preliminary, and final prices, induced by differences in meter readings. The differences were:

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[1] The largest portion of the payments to generators and dispatchable load are not related to transmission and security constraints, but rather to other factors such as dispatch deviations, and message filtering. The MSP discussion paper identified such payments and questioned whether these should remain as they are, so there could be some uncertainty about these being sustained in future.

[2] Recommendation: Preliminary & Final Pricing; May 31, 2002, IMO_STM_0001, p.6

- Type 1: Difference resulting from failures in telemetry, operational data feed or the DSO itself;
- Type 2: **Differences resulting from the locational disparity between operational and revenue metering;**
- Type 3: Differences resulting from the accuracy levels between operational and revenue metering; and
- Type 4: Differences owing to changes in the revenue metering data as are result of VEE.

It is the type 2 locational differences, which are relevant to the current assessment. Type 2 differences reflect physical losses as well as apparent losses due to station service load, which may be served by a feed between the two meter points.

Unfortunately the locational difference data is not easily determined.

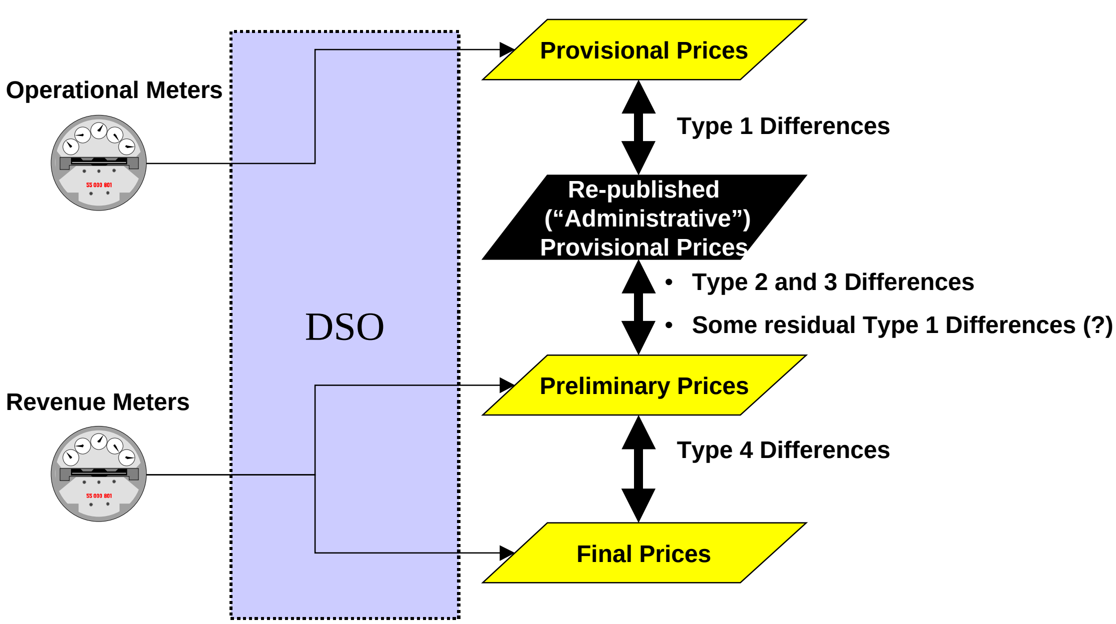
We have postulated 2 possible approaches to making adjustments to schedule quantities.

a) One alternative is to consider the differences between points to be somewhat of a variable, and that the best estimate is based on recent historical data. For example, if station service levels change this can affect the adjustment. Based on historical data, this would be relatively straightforward to determine.

b) The second approach is to assume a constant difference, reflecting relatively fixed physical losses and a fairly constant (or zero) impact from station service load. Determining this quantity might require far more time-consuming measurements at each facility. In light of the data observed below, the former implementation may be subject to error.

The diagram below shows where these differences manifest themselves between the different prices identified above.

Figure 1 : Differences Between Provisional, Preliminary and Final Prices



Operational vs. Revenue Mater Data

We have looked at a sample for the first seven days of December 2002, comparing operational meters and revenue meter results[3]. Observed differences from these would not be due to type 2 causes alone, but would also reflect type 1 (e.g. telemetry or operational data feed problems) and type 3 accuracy differences in the meters. Even with these type 1 and type 3 differences, this comparison is of potential interest, as noted above, because one possible alternative implementation of the schedule adjustment would be to look at recent historical differences in the two sets of meter quantities.

Table 2 : Operational versus Revenue Meter Differences

Difference	Fossil	Hydroelectric	Adjusted Hydroelectric	Total Fossil & Adjusted Hydroelectric
MW	6.3	-72.9	-29.9	-23.6
% Dispatch	0.12%	-2.03%	-0.95%	-0.27%

Averages over the week were taken in order to smooth out some of the type 3 random inaccuracies in the meters. Aggregates across groups of generators is intended to suggest the net impact on average of such differences.

The aggregate data for fossil units shows a very small difference on average, just over 0.1%. Note that a positive difference indicates the operational meter has a higher reading than the revenue meter. Individual facilities exhibited larger differences, as much +/- 5 MW per unit, which is roughly 1% of the capability of some of these units.

Hydroelectric units exhibited some surprising results. On average the operational meter was **lower** than the revenue meter by more than 2%. This is not consistent with the expected result. Some hydro plants do have operational meters on the high side of the unit transformer, which may be further from the generating unit than the DMP; such cases should lead to small negative differences. For several facilities, the physical locations for the meters is the same (there is only one meter providing both values), and these should lead to 0% difference. However, for many facilities the revenue meter should read less due to losses as power flows from the operational meter to the DMP. Station service is fairly small at hydroelectric plants, so typically the unit transformer losses are most significant.

Since some of the worst cases (negative differences) were at remote plants, it is possible type 1 differences (telemetry problems) influence the result. Removing some of the more questionable results (more than 5 MW differences at a plant) gives the Adjusted Hydroelectric figure, which now approximately a –1% difference.

The aggregate figure for fossil and adjusted hydroelectric is -0.27%. These negative values are believed to be dominated more by telemetry and meter accuracy problems than by location differences of the two meters.

Inference from Revenue Meter Loss Adjustments

Another approach is to consider unit transformer information, some of which may have been identified when revenue meters were being registered.

The DMP is the high voltage side of the unit or plant transformers. Part of the revenue meter registration was to determine the losses or adjustment factor between the meter and DMP. While

[3] Operational meter quantities are from the PI database; revenue meter quantities are the AQEI used in Settlements, derived for the DMP through the totalization process from the underlying revenue meter quantities.

most revenue meters are located on the high voltage side of the transformer, transformer loss values were required for those meters on the low side of the transformer. Knowledge of unit transformers also suggests typical values for the losses are in the 0.3% to 0.7% range. Where specific measurements were / are not available the value was / is assumed to be 1%.

Where operational meters are on the low side (most common situation) the above noted transformer losses would be relevant to the adjustment of schedule quantities to the DMP. Station service feed at some plants would also tend to drive up the total loss or adjustment value. For other plants we see that revenue meters and operational meter data are identical, i.e. a 0% difference, and in a few instances, the operational meter reads less. That is, it is expected that in specific cases, the adjustment could be greater than 1% or could be negative.

Representative Loss Adjustment

Given that it is difficult to accept the above sample of measured differences between operational and revenue meters as the appropriate adjustment, even in aggregate, we conclude that using 0.5% to 1% would appear to be a representative ball park figure for the adjustment. However, it recognized that for some facilities, the adjustment may well be more than 1%, while for a limited number the correct value would be negative.

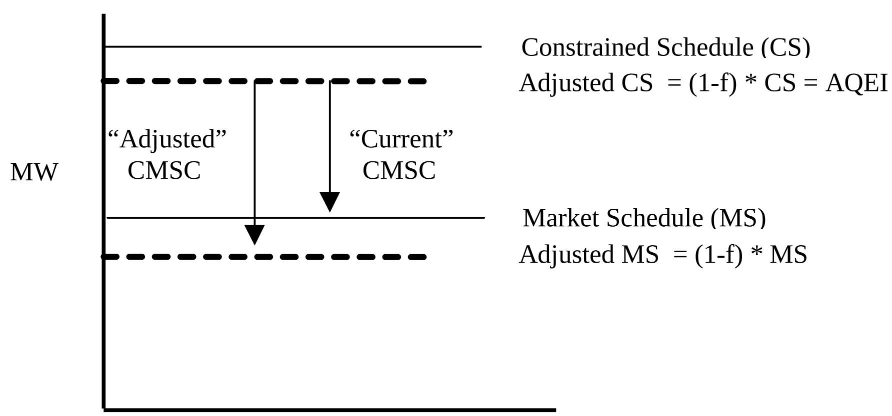
5.5.3 Translating the Loss Adjustment into Changes in CMSC

In order to quantify the impact on the CMSC paid, consider the typical situation in which the DMP is more distant from the generation facility than the operational meter and the currently implied scheduling point. Assume that, as determined by some process, the reading at the DMP is f % lower than the operational point (e.g. f=1% as above).

Constrained On Case

Assuming the generator's operational meter equals the dispatch (or constrained schedule), in a constrained on situation, figure 2 shows how CMSC would be currently calculated and how the adjustment of the schedules to DMP would lead to a different, or adjusted, CMSC.

Figure 2: Current vs. Adjusted CMSC – Constrained On



Both the adjusted CS and MS at the DMP are f % lower than the corresponding quantities which are currently quoted at the operational meter point.

The CMSC calculation is:

CMSC = OP (MS) – max [OP (CS), OP (AQEI)]

With some simplifications, this can be translated into a more intuitive formulation:

CMSC = constrained on MW * [Offer – MCP]

= [min (CS, AQEI) – MS] * [Offer –MCP]

This suggests that the CMSC paid is proportional to the effective constrained on quantity, i.e. the difference between the market schedule and the lesser of the constrained schedule or the actual output. Thus changes in the applied MW quantities directly influence the constrained on CMSC.

In Figure 2, the current application suggests CMSC is proportional to AQEI – MS, since AQEI, the revenue meter quantity at the DMP is, in this case, equivalent to (1-f) * CS. Thus,

Current CMSC is proportional to (1-f) *CS – MS

If the DMP adjustment were applied, then the relevant MS for the calculation is the adjusted value (1-f) * MS, and:

Adjusted CMSC is proportional to (1-f) * CS – (1-f) * MS

The impact of using adjusted schedules for CMSC in a constrained on case is that CMSC paid to a generator would be higher:

Adjusted CMSC - Current CMSC is proportional to

[(1-f)* CS – (1-f)*MS] – [(1-f) *CS – MS]

= f * MS

Thus if MS = 100 MW, CS = 200 MW, and f = 1%,

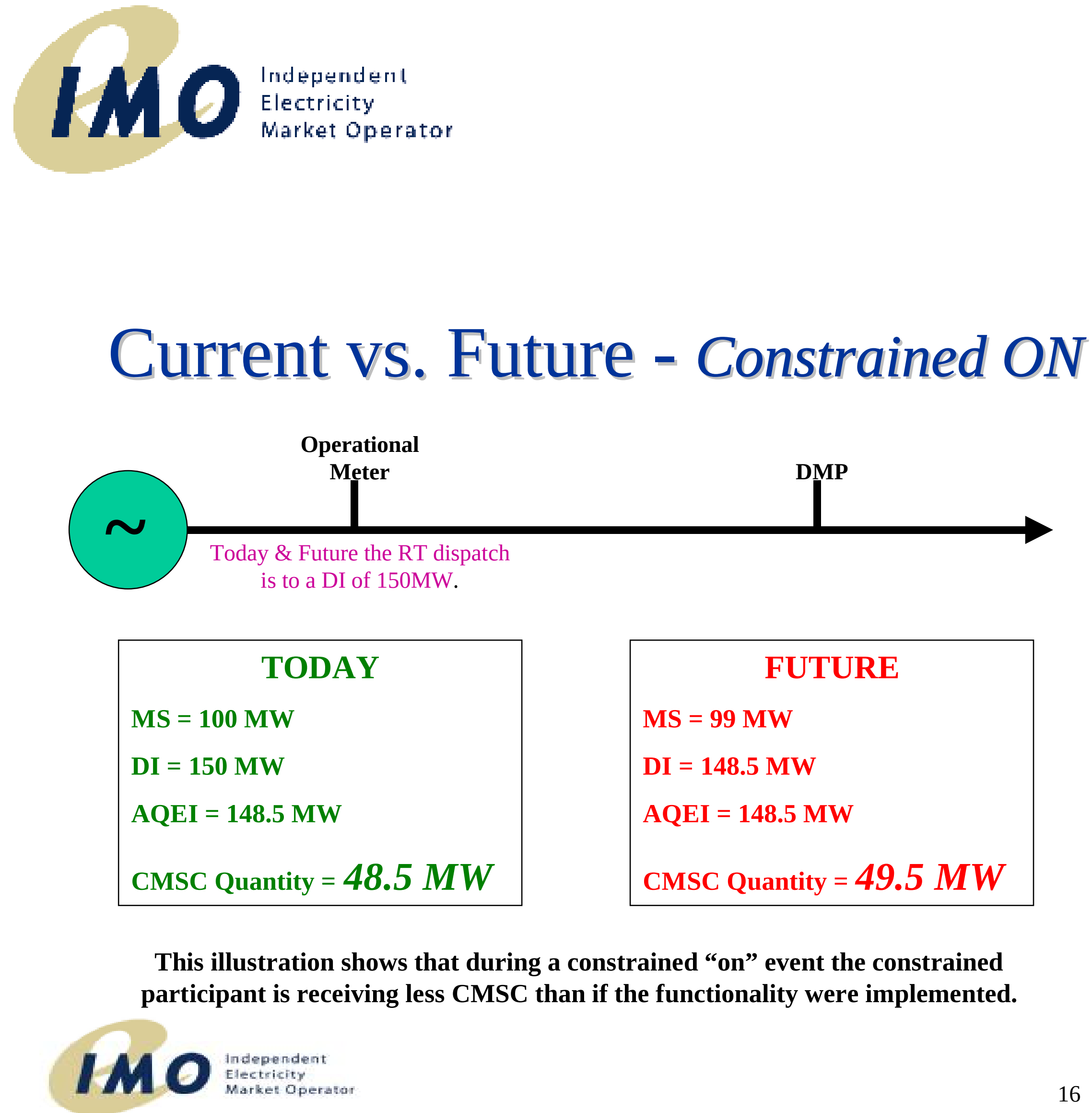
current CMSC is based on (1-1%) * 200 – 100 = 198 – 100 = 98 MW

adjusted CMSC is based on (1-1%) * 200 – (1-1%) *100 = 198 – 99 = 99 MW

difference in CMSC based on 99 – 98 = 1 MW

In this constrained on example, where the constrained on MW (CS –MS) is comparable to the market schedule quantity, the current CMSC underpays by about 1% (= f) relative to the adjusted CMSC calculation.

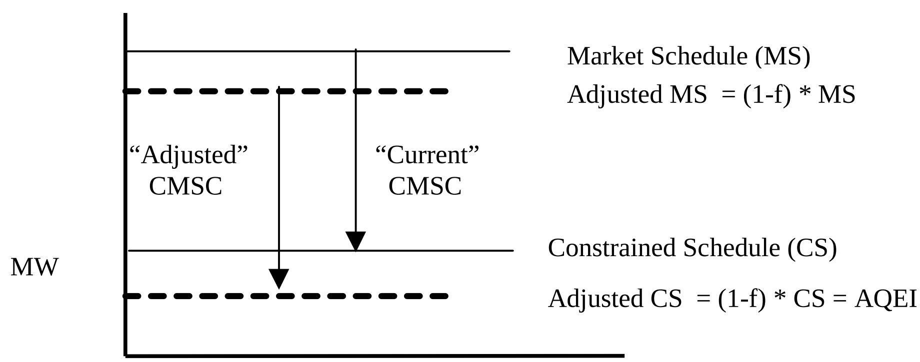
There are many other possible scenarios – where the market schedule is higher or lower, where the actual production as viewed at the operational meter is above or below the constrained schedule. Each leads to a different result, with higher or lower impacts. However, the above case, where the impact is comparable to the adjustment factor f, is used later as representative of the magnitude of the impact on constrained on CMSC payments.



Constrained Off Case

A similar assessment can be developed for a constrained off case.

Figure 4: Current vs. Adjusted CMSC – Constrained Off



With some simplifications, the constrained off case can be translated into the more intuitive formulation:

CMSC = constrained off MW * [MCP – Offer]

= [MS - max (CS, AQEI) * [MCP – Offer]

Based on Figure 3, for the constrained off case:

Current CMSC is proportional to MS – CS

If the DMP adjustment were applied, then the relevant MS and CS for the calculation are again the adjusted values, and:

Adjusted CMSC is proportional to

(1-f) * MS – (1-f) * CS

= (1-f) * (MS – CS)

The impact of using adjusted schedules for CMSC in a constrained off case is that CMSC paid to a generator would be lower:

Adjusted CMSC - Current CMSC is proportional to

[(1-f)* (MS – CS)] – [MS – CS]

= f * (MS – CS)

Thus if MS = 200 MW, CS = 100 MW, and f = 1%,

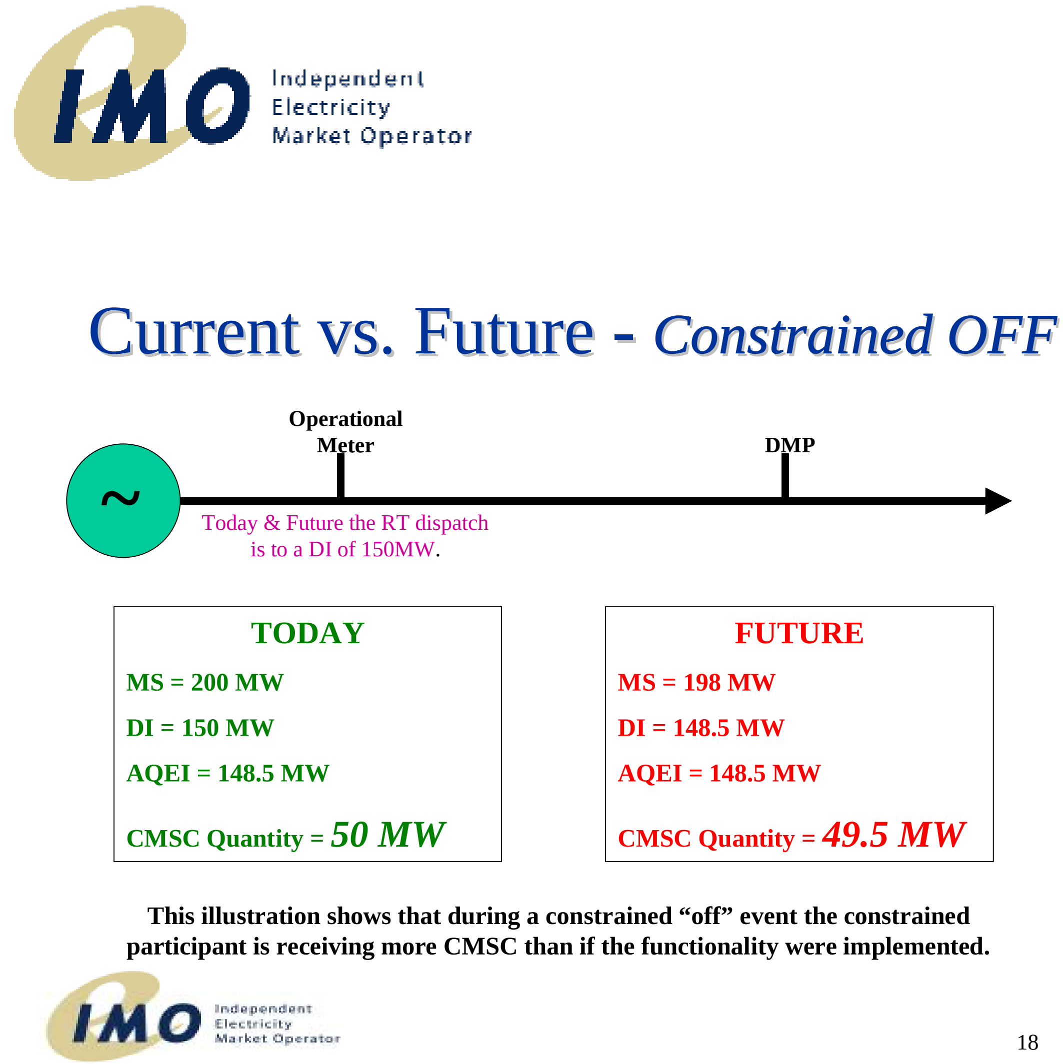
current CMSC is based on 200 – 100 = 100 MW

adjusted CMSC is based on (1-1%) * 200 – (1-1%) *100 = 99 MW

difference in CMSC based on 100 – 99 = 1 MW

In this constrained off example, the current CMSC overpays by about 1% (= f) relative to the adjusted CMSC calculation.

The difference of 1% (or f) is not dependent on the selection of MS or CS, and would apply generally in constrained off cases. Of course to the extent that the actual production is different from dispatch, difference due to the DMP adjustment would vary in specific cases. Again, this simple case is selected as representative.



5.5.4 Application to Observed CMSC Results

The above representative impacts are applied to CMSC payments to derive the estimated CMSC impact of adjusting schedules to the DMP.

It was concluded that the loss impact or adjustment factor is in the range of 0.5% to 1%, based not on observed meter reading differences but primarily on losses across the unit transformers.

It was also concluded that the impact of the adjustment on CMSC for constrained on cases would be to add about f % to CMSC (the current CMSC represents an underpayment). For constrained off cases, the impact of the adjustment would be to reduce CMSC by about f% (the current CMSC overpays).

The CMSC data quoted at the beginning of this section covers the 8 months from May to December 2002. To extrapolate to a 12 month period, we simply add another 50% to the figures. This leads to approximate annual CMSC payments to fossil and hydroelectric generators of 1.5 * $29.6 M = $44.4 M for constrained on operation and 1.5 * $43.6 M = $65.4 M for constrained off operation.

Table 3 : Net Annualized CMSC Impacts

	Annualized CMSC ($M)	CMSC Decrease ($M)	
		Adjustment factor f = 0.5%	Adjustment factor f = 1.0%
Constrained On	44.4	-0.5% * 44.4 = - 0.222	-1.0% * 44.4 = - 0.444
Constrained Off	65.4	+0.5% * 65.4 = 0.327	+1.0% * 65.4 = 0.654
Total	**109.8**	**0.105**	**0.210**

Because of the opposite effects of the impact on constrained on and constrained off payments, the net effect is estimated to be relatively small. Even for the larger adjustment factor, 1%, the annual net decrease in CMSC is $210,000.

5.5.5 Quantifying CMSC Impacts

- Import and export CMSC payments are not affected due to the use of schedules for settlement;
- Preliminary review indicates that CMSC payments for OR are also unaffected due to the use of schedules for settlement; and