actions the MCE can take to resolve a constraint by limiting the cost that is willing to be incurred to control it.

The objective of the constraint control logic is to dispatch the least cost set of resources to meet the target facility limit that dispatch is trying to control the constraint to at a marginal cost at or below the transmission constraint penalty factor. The transmission constraint penalty factor does not directly impact the marginal value of a constraint as long as the constraint can be solved by resources whose effective costs are lower than the value of the penalty factor. The cost of using a resource to control a constraint, or its effective cost, can be approximated by using the following equation.

$$Effective\ Cost\left(\frac{\$}{MWh}\right) =$$

$$\left|\frac{(Energy\ Price + Loss\ Price + Congestion\ Price\ (all\ binding\ constraints) - Incremental\ Cost)}{Dfax}\right|$$

If the flow on the constraint cannot be controlled below the level to which dispatch is attempting to control the facility it results in a constraint violation in the MCE optimization. The transmission constraint penalty factor is then used to set the marginal value of the violated transmission constraint.

PJM internal constraints including Market-to-Market coordinated constraints, regardless of voltage level, are defaulted to a $30,000/MWh transmission constraint penalty factor in the Day-ahead MCE when determining the Day-ahead security constrained economic dispatch, known as the dispatch run, and $2,000/MWh in the determination of Day-ahead Prices in the pricing run. All PJM internal constraints, regardless of voltage level, are defaulted to a $2,000/MWh transmission penalty factor in the Real-time Energy Market. PJM may adjust the default penalty factor in Real-time for Market-to-Market coordinated constraints to reflect the operating practices which are mutually agreed upon with the neighboring RTO/ISO for managing such constraints.

PJM can also adjust, for an individual constraint, the default penalty factor or temporarily change the default penalty factor for an individual constraint, in order to reflect system operational needs and the cost of the resources available to effectively relieve congestion on the constraint. When PJM identifies that the effective cost of controlling actions available to relieve congestion on the constraint is not consistent with the default penalty factor, the penalty factor is increased or decreased as documented in the Transmission Constraint Penalty Factor Adjustment Guidelines.

In Real-time the transmission constraint penalty factor value for an individual constraint is utilized in both the dispatch and pricing runs.

2.18 Applying Stability Limits in the Market Clearing Engine

The ability of a generating unit or a group of generating units to maintain synchronism following a system disturbance can be identified using real time and study applications such as the PJM Transient Stability Analysis (TSA) tool. Based on results from TSA, stability limits will be established and logged within PJM's TO Connection. For real power (MW) stability limits only, TO Connection stability limits will be translated into a corresponding generator output constraint (in MW) for a single generator or a group of generators. If the system disturbance is identified and the applicable stability limit is known prior to the Day-ahead Market closure, it will be included in the Day-ahead Market Clearing Engine. The generator output constraint will limit the sum of the dispatched MW (including ancillary services) of the affected generating unit(s) while dispatching them in economic merit order up to the stated limit. Similar to other operational constraints (e.g. ramp rate limitations) the shadow price of the generator output constraint will not be included in the LMP. Any generating unit or group of generating units that is reduced using a generator output constraint is not eligible for lost opportunity cost credits for the MW reduction associated with honoring the stability limit.

PJM will communicate on a periodic basis statistics on the frequency, location and number of affected generating units to the extent it is consistent with PJM confidentiality rules.

Additional details regarding stability limits may be found in Manual 3, Section 3.9.1, Manual 12, Section 5.5 and Manual 28, Section 5.2.6.

2.18.1 Treatment of non-Real MW Stability Limits

Per Manual 3, Section 3.9.1, there are a total three types of stability limits: real power, reactive power and station. The Market Clearing Engines will not consider either the reactive power or station stability limits. However, if a generating unit or a group of generating units are being reduced for a station stability limit, it will not be eligible for lost opportunity cost credits for the MW reduction associated with honoring the stability limit.