Lake Erie Emergency Redispatch (LEER) Procedure

Lake Erie Security Process Training

May 2002
Prepared By Lake Erie Security Process Working Group
Agenda

• Why LEER? - Goals, Vision, & Principles
• LEER Procedure Review
• Settlement
• Background and History
• Examples
• Drill Procedure
Goals

- To protect **Firm Load** served by Non-Firm Transmission Service within Lake Erie Region via Redispatch option in lieu of TLR curtailments.

- Increase system reliability
Vision

• Incorporation of collaborative actions by both the market and system segments

“Market” Solutions
Pre-arrangements
MRD

“System” Solutions
SRD
Real Time Measures

“Emergency” Solution
LEER
Basic Principles

- No Firm load should be shed when generation is still available
- Procedure must not conflict with FERC filed tariffs or NERC policies (Policy 9 in particular)
- Prior agreement to decisive action is essential
- Act now, dispute later
- Information confidentiality must be observed
- Keep it simple
Lake Erie Circulation (LEC)

- Growing since early 1990s from about 500 MW
- Recorded levels exceeding 1,600 MW.
- Heavy counterclockwise LEC using up transmission capacity of QFW and MECS-IMO Interface. (entering Ontario in the Niagara area and exiting via Michigan)
- Impedes
  - Commerce from the North East into Ontario
  - Michigan’s ability to purchase from Ontario & New York
  - Transactions from North East (NY & PJM) to the Midwest.
- Numerous transaction curtailments since 1995 due to limitations in the Niagara area (QFW)/ NY - Ont. or Michigan-Ontario Interconnections
- Spring and Summer of 1988, 1999 escalated to almost daily problems
- In 1998 declared:
  - 33 TLRs on QFW (7 in 1999)
  - 21 TLRs on the Michigan-Ontario Interconnections (15 in 1999).
500 MW flow on QFW means a total east to west transaction of 4200 MW.

Factors based on PTDF Viewer Data file 1999/02/18
Power Transfer from Maritime area to Chicago area
Basic Elements of Agreement

- An emergency procedure intended to avoid firm load cuts
- Intended primarily for non-firm transmission service
- A first of its kind involving multiple Control Areas crossing Regional boundaries
- Implemented after voltage reduction and dispatchable/interruptible load cuts - (caveat)
- Emergency energy purchases to be made under the provision of Interconnection Agreements and/or Market Rules.
Some LEER Definitions

- Dependency (MW):
  - Forecast/Actual Load - Resource - MW Voltage Red. - MW dispatchable/interruptible

- Dependent RAs/CAs: the sink RAs/CAs of a dependent transaction

- Constrained RAs/CAs: where a potential or actual FG overload is identified (these RAs direct redispatch)

- Controlling RAs/CAs: where generation shift (INC or DEC) is available and identified
Overview of LEER Procedure

- **Dependent RA: Initiate LEER**
  - posts dependency on RAIS, updated throughout the day, & initiate LEER Hot Line conf. call

- **Participating RAs identify potential, impactive constraints as soon as possible (TLR 1)**

- **Impacted RAs/CAs assess effects of redispatch using GSFs** (go to RAIS Home page or “Central Repository for Security Events” page [https://www.nerc.net/crc](https://www.nerc.net/crc)) and identify a/v generation

- **E-Tag created by PSE or LCA (DEC unit)**

- **Implement LEER at NERC TLR Levels 3a and higher**

- **Energy settled at prevailing emergency energy price or local tariff**

- **Reduced generation receives energy credit according to local tariff rules**

- **Owner of protected transaction bears all costs**
LEER Cancellation

- Dependent RA to cancel LEER when dependency no longer exists.
- Constrained RA to cancel LEER if system constraint sans Control Action no longer exists.
- Controlling RA to cancel LEER if controlling units no longer available.
- RA providing emergency energy may cancel LEER if emergency replacement energy becomes u/a.
- LEER transaction curtailed by TLR because it contributes to constraint on another flowgate.
Interface with NERC Policy

- **Not** to conflict with NERC Operating Policy 9
- Dependent transactions - protected from curtailment through re-dispatch
- Transmission service (non-firm hourly transmission service Level 2) required **but** after the fact
- Use of “MRD”- tag to enter into and be evaluated by IDC note it as a “LEER” transaction in comments field?
- Re-dispatch arranged by “Dependent” CA (Sink) with INC/DEC generator PSE’s
- Once re-dispatch begins to flow to protect dependent transactions categorized as protected transactions.
Interface with NERC Policy (Cont’d)

- Additional loading on flowgate **not** to be associated with protected transactions so as long re-dispatch in place.

- Re-dispatch can be applied to a part or all of a transaction, as required by the magnitude of the dependency.

- Portions of transactions for which re-dispatch is implemented are protected from further non-firm curtailment on constrained flowgate.

- Unprotect portion on constrained flowgate may be curtailed

- Constraint on another flowgate can cause protecting transaction to be curtailed, exposing formerly protected transaction to curtailment.
**Interface with NERC Policy (Cont’d)**

- LEER does NOT transform non-firm transactions into firm transaction

- LEER does not encourage use of non-firm transmission to supply firm load

- unwinding of LEER to “pre-LEER state” unrestrained by new constraints on other flowgates

  But...Previous LEER protected Tx re-evaluated according to Policy 9 rules.
Settlement Principles

- Owner of protected transaction (*Dependent System*) bears **all** costs.
- Billed as Scheduled - Source to Sink.
- Sink *Controlling System* initially incurs all costs as “quasi” EE purchaser.
- Sink *Controlling System* forwards “compiled” invoice to *Dependent System* for full cost recovery.
- EE Settled on monthly basis
Settlement

- **Dependent System's RA/CA** required to compensate **Controlling Systems’ RA/CAs**, or applicable PSE(s) for:
  - charges incurred in acquiring replacement energy
  - transmission service cost as applicable
  - ancillary service charges, consistent with existing tariffs
- **INC. Generators** paid in accordance with:
  - local tariffs and control area agreements or
  - at the higher of the prevailing emergency energy price, hourly market price, or imbalance price, as applicable.
- **DEC. Generators** compensated (CMSC) in accordance with:
  - local tariffs and control area agreements or
  - constrained OFF Settlement Tariffs
  - Where applicable, the Dependent System's RA/CA recovers expenses based on their current settlement practices.
LEER Development

- LESPWG developed final LEER draft in Sept., 1998
- Areas participated: PJM, NYISO, IMO, MECS, FE, DQE, AP(APS), AEP
- Operation reps + affiliated marketers + individual marketing reps
- Six participants signed agreement Dec./98; committed to continue refining LEER in 1999
- LEER filed with FERC Feb./26/1999
LEER Development

- Two interventions filed in March 1999
- LEER added to NYISO Tariff - April 1999
- FERC conditionally accepts LEER - May 12 1999
- LEER Compliance filing - June 1 1999
- LEER first Dry Run June 2 1999
- FERC accepts LEER compliance filing Aug 2 1999
- LEER Agreement Document restructured - Fall 1999
LEER 2000 Development

- Materially the same as the original procedure
- Reorganize document to include:
  - principles and elements of agreement in main body
  - procedural elements in appendices
- Added and strengthened language
  - referring to NERC Policy compliance
  - addressing FERC’s questions
LEER Development

- Participants re-sign in June 2000 (FE joins)
- File update with FERC in July 2000
- FERC accepts revised LEER - September 2000
"We [FERC] find the LEER proposal is an additional measure that goes beyond the requirements of our December 16 Order. The LEER participants have designed an emergency assistance scheme that obligates members to assist each other not only by selling emergency power (the traditional focus of emergency assistance agreements), but also by cooperating in regional redispatch arrangements."

FERC goes on to state that they "do not share the intervenors' concerns that the LEER proposal is unclear" and that they "disagree" that it is discriminatory since it only applies to LEER participants recognizing that participation is open to those who wish to join in the agreement and "are willing to accept the obligation to provide emergency assistance".
Example 1

Limiting facility - Actual overload on South Ripley to Erie 230 kV tie line facility is overloaded by 14.2 MW

Starting conditions:
FE purchasing 500 MW from IMO non-firm
FE has no internal generation available

PJM dfax relative to Kammer swing:
- S. Ripley Gen .652
- Dunkirk Gen .344
- IMO system .100
- NYISO system .08
- FE system -.04
- PJM Warren CT -.128
- PJM system .03
- AP system .00
- VAP system .00

Redispatch Option:
keep existing transactions, reduce S. Ripley, FE provide energy to NYISO(S.Ripley) from IMO

line relief mw = X MW (lower @ S.Ripley raise @ IMO)
14.2 = X MW (.652 + .100)
14.2 = X MW (.652 + .100)
X MW = 25.72

FE buys 525.72 MW from IMO
S. Ripley reduces 25.72 MW
FE provides 25.72 MW to S. Ripley (via NYISO)

Curtailment Option:
Cut IMO-FE transaction to effect 14.2 MW relief.
Raise FE system | lower IMO system
(-.04 dfax ) + (-.10 dfax ) = (-.14 dfax )
14.2MW/-14 dfax = 101.5 MW shift
101.5 MW cut reduces flow by 14.2 MW
FE still receiving 398.5 MW.
Example 1
IMO - FE  500 MW Power Transfer

A 14.2 MW overload on South Ripley would require

- 101.5 MW IMO - FE cut (IMO-South Ripley = +10% & FE System - 4%)
  or
- S. Ripley Gen ↓ & IMO Generation ↑ (S. Ripley Gen - 65.2% plus +10%)

Factors based on PTDF Viewer Data file 2000
Power Transfer from IMO area to FE area
Example 1: Coordination Procedures

1. FE identifies dependency of 500MW (IMO energy) and notifies LESC’s via RAIS.

2. Lake Erie Reliability Authority (LERA) review dependency and projected system constraints. PTDF matrix, GSF matrix and IDC used to determine which transactions affect projected constraints and identify possible redispatch options. PJM is identified as the Constrained RA (Constraint = South Ripley - Erie South 230 kV). The controlling RA is identified as NYISO (Controlling Action Lower = South Ripley Gen).

3. RAs discuss dependency and options via LEER Hot-line (Conference Call). Affected parties are identified.

4. PJM determines current DFAX/GSF based on on-line/off-line studies (South Ripley NUG = 65% help)

5. FE, PJM, and NYISO agree upon GSF/DFAX and location of replacement energy. (IMO Replacement Energy = 10% hurt).
Example 1 (con’t)

6 FE notifies LERAs via RAIS of agreed upon actions and protected transactions.

Summary of Distribution Factor Effect

Redispatch Option:
\[ X = \frac{14 \text{ MW constraint}}{(65\% \text{ Controlling Action} - 10\% \text{ Replacement Energy})} \]
\[ X = \frac{14 \text{ MW}}{(55\%) } \]
\[ X = 25 \text{ MW replacement energy} \]
Lower South Ripley Gen by 25 MW.

Curtailment Option:
\[ X = \frac{14 \text{ MW constraint}}{(4\% \text{ FE Load} + 10\% \text{ IMO energy reduction})} \]
\[ X = \frac{14 \text{ MW}}{(14\%)} \]
\[ X = 100 \text{ MW reduction} \]
25 MW redispatch protects 100 MW of FE Load.
Example 1 (con’t)

7 PJM (Constrained RA) directs LEER procedure at request of FE (Dependent CA).

8 PJM (Constrained RA) notifies FE (Dependent CA) when constraint is relieved.

9 PJM (Constrained RA) notified NYISO (Controlling RA) when controlling action is no longer required.

10 FE (Dependent RA) cancels replacement energy (if applicable) by notifying IMO.
LEER Drill Scheduled for May 29, 2002

- PJM acts as constraining CA
- AEP/FE - PJM-West constraining facility
  WYLIE RIDGE 345/500 TX7-WYLIE
  RIDGE 345/500 TX5
- IMO will act as dependent system
- Drill Start at ~0800 - 1130 DST.
Step Procedures for May 29, 2002 LEER (Lake Erie Emergency Re-dispatch) Drill

Drill Scenario: AEP/FE- PJM West Constrained with IMO as Dependent RA and CA

- **Constrained RA/Flowgate:** AEP/FE- PJM West
- Dependent System: IMO
- Potential **Controlling RA Source** (**INC** unit) – **Sink** (**DEC** unit) pairs:
  - **Source** (**INC** unit CA’s): NYISO, PJM
  - **Sink** (**DEC** unit CA’s): FE, AEP, MECS

Note: Times have been selected arbitrarily and can be changed to suit operating conditions at the time.

All times are based on Eastern Standard Time (EST)

Procedures:

1. **08:30 EST:** The Dependent RA determines the dependency situation as follows:
Dependent Control Area: IMO

<table>
<thead>
<tr>
<th>CA Peak Load Forecast</th>
<th>MW</th>
<th>Hour Ending (EST):</th>
</tr>
</thead>
<tbody>
<tr>
<td>less Committed Resources</td>
<td>MW</td>
<td></td>
</tr>
<tr>
<td>Less Voltage Reduction “Control Action” relief</td>
<td>MW</td>
<td></td>
</tr>
<tr>
<td>Less Interruptible/Curtailable “Control Action” relief</td>
<td>MW</td>
<td></td>
</tr>
<tr>
<td>Control Area Total Dependency</td>
<td>MW</td>
<td></td>
</tr>
</tbody>
</table>

2. **08:45 EST**: The **Dependent RA** (IMO) to Provide “Dependency” Data via **RAIS**’s “System Emergency” messaging page using the message as per template 1 in Appendix D:

3. **9:00 EST**: The **Dependent RA** (IMO) establishes a conference call with the **Constrained RA** (PJM) and other (impacted) LEER participants using **LEER Hotline** *(Selected based on participation involvement for the simulation only)*

   Conference Call Agenda
   a. Role Call
   b. Discussion of IMO Dependency situation:
END
Factors based on PTDF Viewer Data file 1999/02/18
Power Transfer from Maritime area to Chicago area

East to West Power Transfer

- PTDF for QFW = 12%
- A 500 MW overload on QFW could potentially restrict 4200 MW of east to west transaction.