Briefing note: LSRs methodology

Prepared by London Economics International for Connecticut Department of Public Utility Control

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This briefing note addresses some questions that arose at the technical meeting on June 15, 2006 and in written comments regarding forecasting of LSRs. In principle, implemented an LSR projection that follows the conceptual building blocks of ISO's methodology and comports with the indicative LSR projections presented by ISO (including the methodology David LaPlante detailed in his prepared testimony in the LICAP proceeding, dated August 31, 2004)[1]. After further reviewing ISO documents from the ICR Working Group and existing Market Rules and planning procedures, we would have refined some of the inputs and calculations of our LSR projection, although our basic approach remains the same – we are implementing a simplified, deterministic approximation of ISO's modeling-intensive probabilistic analysis.

In this brief note, we first describe the basic approach and then highlight areas of refinement. We then document the resulting 2007 estimated LSR for Connecticut. Lastly, we replicate the LaPlante estimation of 2006 LSR for Connecticut, based on data available as of August 2004 (when the LaPlante testimony was prepared) combined with our refined methodology. We compare this "back-cast" against the Connecticut LSR projections that David LaPlante referred to in his August 2004 testimony. This back-casting exercise highlights the consistency of the proposed methodology with ISO's own indicative figures for LSR.

Basic concept of LSR

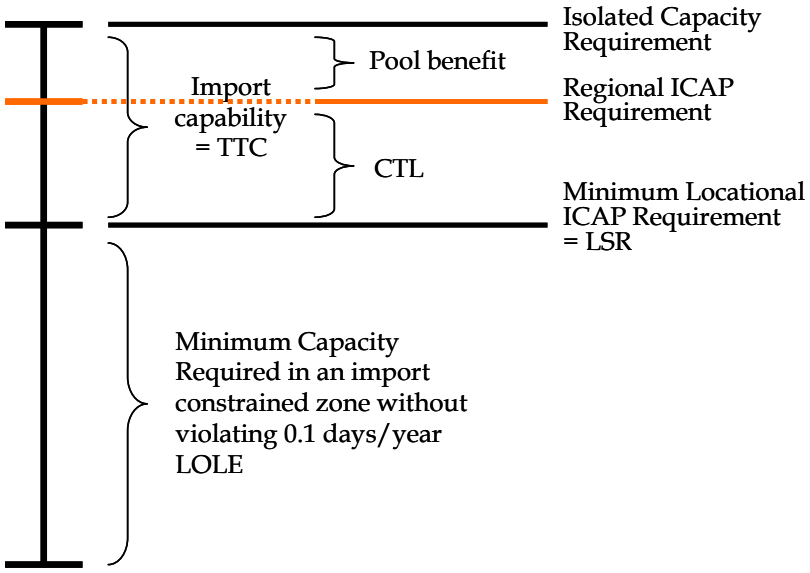
LEI's LSR methodology is based on the proposed LSR methodology described in David LaPlante testimony dated August 31, 2004, which was reiterated in his affidavit appended to the Settlement Agreement for the Forward Capacity Market. Currently, the question of LSR methodology is being debated in the ICR Working Group and we will continue to monitor this process and make refinements, if necessary, to our approach.

On page 35 of David LaPlante's August 2004 testimony, the LSR for a zone can be estimated using the following two approaches:

- LSR = Isolated Capacity Requirement – TTC; or
- LSR = Regional ICAP Requirement – CTL.

[1] David LaPlante in his affidavit attached to the FCM Settlement Agreement referred back to this testimony, confirming the methodology used in the August 31, 2004 testimony is appropriate for LSR estimations. See FCM Settlement Agreement Attachment 6: Affidavit of David LaPlante on page 3. "The methodology used to derive these Local Sourcing Requirements is as described in my testimony in this proceeding (Prepared Direct Testimony of David LaPlante, Exh No. ISO-1, at 38:8-43:12)."

Figure 1. Relationship between LSR, TTC and CTL



Note: See David LaPlante's prepared testimony in the LICAP proceeding, dated August 31, 2004, page 35.

Due to the difficulty of estimating CTL[2], we had decided to use the first approach, starting from Isolated Capacity Requirement.

Refinements to LSR methodology

According to ISO working group document[3], LSRs should take into account factors such as:

- Load uncertainty due to weather
- Generation forced and planned outage
- Load and capacity relief from operating procedures
  - Load response program
  - Energy assistance from surrounding Control Area
  - Voltage reductions

The third bullet point in the above list is in fact critical, as it is one of the differentiating features between LSR and Operable Capacity metric. In the *DPUC Needs Assessment*

[2] CTL is a function of TTC and pool benefit. Pool benefit is hard to estimate since it is not a linear function of TTC. See ISO-NE presentation, "*New England Regional System Plan (RSP 06) Incremental LOLE Analysis*" March 15, 2006.

[3] See ISO-NE presentation, "*Review of current Long-Term Installed Capacity Requirement Methodology Used in the Regional System Expansion Plan*" March 28, 2006 and "*Local Sourcing Requirements in the FCM – Straw Proposal for Discussion*" May 11, 2006.

released on June 5, 2006, the LSR forecast for Connecticut (and SWCT) was overestimated, because of the load and capacity relief components.

We originally included demand response resources in the Installed Capacity, and therefore overestimated the Capacity Outage Adjustment and the Availability Adjusted Demand. Furthermore, by not exhausting local and capacity relief from operating procedures available to ISO, we overestimated the Isolated Capacity Requirement, as highlighted in Figure 2 below.

Figure 2. Excerpts from Figure 14 from *June 5 Needs Assessment*

(line)	(calculation)	*Greater Connecticut*	2007
a		Peak Demand	7,280
b		Capacity Outage Adjustment [1]	990
c	= a + b	Availability Adjusted Demand	8,270
d		Assumed Planning Reserves [2]	1,155
e	= c + d	**Isolated Capacity Requirement**	**9,425**
f		TTC	2,500
g	= e - f	LSR	6,925
h		Installed Capacity	7,521
i	= h - g	Local Sourcing Surplus/(Deficiency)	596
j		**Additional Capacity Needed**	**0**
		Capacity Zone (yes/no)	

Due to the inclusion of demand response resources in the Installed Capacity, both Capacity Outage Adjustment and Availability Adjusted Demand are over estimated

Included demand response resources

Overestimated since we did not exhaust load and capacity relief from operating procedures available to ISO

Further, we have changed our approach with respect to the Assumed Planning Reserves. Rather than assume a connection to a contingency unit, we have adopted a 14% planning reserve margin. We have also eliminated scheduled maintenance from the Capacity Outage Adjustment, assuming that little or no capacity will be on scheduled outage during peak demand periods. With these, and the refinements on the use of load and capacity relief, the LSR for Connecticut was reduced for 2007 and is now 6,110 MW. Figure 3 presents the indicative flow chart for deriving LSRs. Figure 4 on the next page presents the numbers used in the LSR derivation.

Figure 3. Indicative process of deriving LSRs

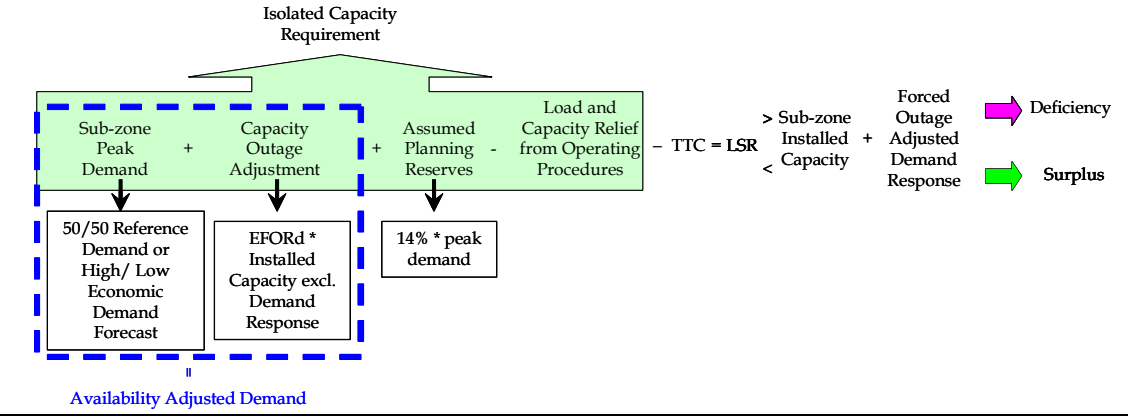


Figure 4. Illustration of LSR calculations for Connecticut in 2007 using available data as of May 2006

LSRs calculation LEI vs. David LaPlante

Prepared by London Economics for CT DPUC

Greater Connecticut

(line)	LSR component	2007	Calculation/ Sources
a	**Peak Demand**	**7,280**	50/50 demand forecast per ISO-NE RSP 2006
b	Installed Capacity (excl. demand response resources)	6,769	ISO-NE CELT 2006 and LEI research
c	**Availability Adjusted Demand**	**7,647**	= a + f
d	Calculated Connecticut EFORd	5.4%	LEI broadly calculation based on 2007 Connecticut unit data
e	Assumed System Maintenance	0.0%	assumed to be zero on peak day
f	Capacity Outage Adjustment	367	= (d + e) * b
g	**Assumed Planning Reserve**	**1,019**	= 14% * a
h	**Load and Capacity Relief from Operating Procedures**	**56**	= sum (j : k)
i	Forced Outage Adjusted Demand Response	575	includes all DR shown in separate Appendix (adjusted by EFORd)
j	Voltage Reductions (1.5% of Peak Load)	109	= 1.5%* a
k	less Minimum Operating Reserve	(54)	CT peak load share of minimum operating reserve
l	**Isolated Capacity Requirement**	**8,610**	= c + g - h
m	TTC	2,500	from ISO-NE RSP 2006
n	**LSR**	6,110	= l - m

Back-cast using 2004 data and comparison to ISO's indicative LSRs

Our latest methodology is consistent with ISO's indicative LSRs and also David LaPlante's testimony. David LaPlante projected a 6,189 MW LSR for Connecticut in 2006 using RTEP 2004 inputs. Using those same inputs, and our methodology, we arrive at an LSR of 6,228 MW, which is less than 1% higher than the LaPlante estimation.

Figure 5. LSR calculation for Connecticut in 2006 using data available as of August 2004

LSRs calculation LEI vs. David LaPlante

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Greater Connecticut

(line)	LSR component	2006	Calculation/ Sources
a	**Peak Demand**	**7,109**	from David LaPlante testimony page 43
b	Installed Capacity (excl. demand response resources)	6,958	from David LaPlante testimony page 43
c	**Availability Adjusted Demand**	**7,486**	= a + e
d	Calculated Connecticut EFORd	5.4%	LEI broadly calculation based on 2007 Connecticut unit data
e	Capacity Outage Adjustment	377	= d * b
f	**Assumed Planning Reserve**	**995**	= 14% * a
g	**Load and Capacity Relief from Operating Procedures**	**53**	= h + i
h	Voltage Reductions (1.5% of Peak Load)	107	= 1.5%* a
i	less Minimum Operating Reserve	(54)	CT peak load share of minimum operating reserve
j	**Isolated Capacity Requirement**	**8,428**	= c + f - g
k	TTC	2,200	from David LaPlante testimony page 35
l	**LSR**	6,228	= j - k