TOTAL COSTS AND MARGINAL COSTS

- The total costs of serving a specified load in a given hour may be expressed as

\[
\text{total costs} = \text{fixed costs} + \text{variable costs}
\]

where each quantity provides the costs for that hour.

- The marginal costs of serving a specified load in...
a given hour are defined by the rate of change of the total costs:

\[
\text{marginal costs} \equiv \frac{\partial (\text{total costs})}{\partial (\text{load})}
\]

- The marginal costs are expressed in $/MWh

The small variations in the load in a given hour \( h \) do not affect the fixed costs because of the long lead times required for the investment decisions.

Consequently, the expression for marginal costs reduces to

\[
\frac{\partial (\text{variable costs})}{\partial (\text{load})}
\]
This expression is used to evaluate short-run marginal costs: the short-run marginal costs are associated with the variable costs.

The long-run marginal costs, associated with the investment decisions, are important signals in long-term planning in the expansion of the system with new resource additions.

The focus of this discussion on marginal costs is exclusively on short-run marginal costs.

Marginal costs in hour $h$ are the rate of change of the variable costs $V(h)$ in hour $h$ with respect to a change in the load in hour $h$, with the loads in all other hours held constant.
DEFINITION OF MARGINAL COSTS

- We consider the total variable costs for a given period

\[ V_{\text{period}} = \sum_{h \in \text{period}} V(h) \]

- For the simplified case where the variable costs are purely a function of the generation outputs

\[ V(h) = V[g(h)] \]

MODELING THE SUPPLY SIDE FOR MARGINAL COSTING

where,

\[ g(h) = \sum_i g_i(h) = \text{system generation in hour } h \]

and

\[ g_i(h) = \text{output of unit } i \text{ in hour } h \]

- For each generating unit

\[ 0 \leq g_i(h) \leq g_{i,\text{max}}(h) \]
so that

\[ 0 \leq g(h) \leq g_{\text{max}}(h) = \sum_{i} g_{i,\text{max}}(h) \]

where

\[ g_{i,\text{max}}(h) = \text{maximum output of unit } i \text{ in hour } h \]

- In this formulation
  - the basic unit of time is an hour and all generation related quantities are in units of \( \text{MWh/h} \)
  - the variables \( g_i(h) \) and \( g_{i,\text{max}}(h) \) are in fact r.v.’s; consequently, so are \( g(h) \) and \( g_{\text{max}}(h) \)
  - the outputs \( g_i(h) \) are dependent on \( g_{i,\text{max}}(h') \)
    - and \( \ell(h') \) for \( h' \neq h, \ h' \in [T_1, T_2] \) and
  - where, \([T_1, T_2]\) is the unit commitment period
MODELING THE DEMAND SIDE FOR MARGINAL COSTING

- The system load is the sum of all individual demands for hour $h$

- In reality, $\ell(h)$ is a r.v.

- We assume that there exist no couplings across periods of the system generation, i.e., $g(h)$ is independent of $\ell(h')$ for $h \neq h'$

BASIC ECONOMIC WELFARE THEORY

- Let

$$B[\ell(h)] = \text{the total benefits customers get from the use of } \ell(h) \text{ MWh/h of electricity}$$

$$\rho(h) = \text{price in } \$/\text{MWh in hour } h$$

- Customers exhibit optimum behavior for $\ell(h)$ chosen to maximize the social welfare
The optimal decision \( \ell^*(h) \) must satisfy the necessary condition of optimality

\[
\frac{\partial B}{\partial \ell} \bigg|_{\ell^*(h)} = \rho(h)
\]

Note that in effect,

\[
\ell(h) = \ell \left( \rho(h) \right)
\]

The social welfare maximization involves the optimization of the total welfare for the entire period

\[
\sum_h \left( B[\ell(h)] - V(h) \right)
\]

The assumption of no multiple period couplings allows the decoupling of the maximization into separate subproblems, one for each hour \( h \); hence, we focus on the welfare maximization for the individual hour \( h \).
The maximization of social welfare is equivalent to the minimization of social costs since

\[ \begin{pmatrix} \text{social costs} \end{pmatrix} \triangleq \text{costs} - \text{benefits} = - \begin{pmatrix} \text{social welfare} \end{pmatrix} \]

\[ = V[h] - B[\ell(\rho(h))] \]

We restate our problem as minimizing social costs subject to the energy balance constraint:

\[
\begin{align*}
\min \left\{ V[h] - B[\ell(\rho(h))] \right\} \\
\text{s.t.} \\
g(h) = \ell(h)
\end{align*}
\]

The solution proceeds with the Lagrangian formulation

\[
\Lambda(h) = V(h) - B[\ell(\rho(h))] + \lambda(h)[\ell(h) - g(h)]
\]

objective function  \hspace{1cm} Lagrangian multiplier  \hspace{1cm} supply-demand constraint
The decision variables are \( g(h) \) and \( \rho(h) \).

The optimal decision is the solution of the necessary conditions of optimality:

\[
\frac{\partial \Lambda(h)}{\partial g(h)} = \theta = \frac{\partial V[g(h)]}{\partial g(h)} + \lambda(h)[-1] = 0
\]

So that

\[
\lambda(h) = \frac{\partial V[g(h)]}{\partial g(h)}
\]

\[
\frac{\partial A(h)}{\partial \rho(h)} = \theta = -\frac{\partial B}{\partial \ell} \frac{\partial \ell}{\partial \rho} + \lambda(h) \frac{\partial \ell}{\partial \rho}
\]

resulting in

\[
\left[ \lambda(h) - \frac{\partial B[\ell(\rho(h))] \partial \ell(h)}{\partial \rho(h)} \right] \frac{\partial \ell(h)}{\partial \rho(h)} = 0
\]
which holds whenever
\[ \lambda(h) = \frac{\partial B}{\partial \ell}\left[\ell(\rho(h))\right] \]

- Since the optimal customer behavior implies
\[ \frac{\partial B}{\partial \ell} = \rho(h) \]
we have that
\[ \rho(h) = \lambda(h) \]

**fundamental result in marginal costing**

Therefore, marginal cost pricing is optimal in a social welfare sense, i.e., at the optimum, the marginal costs \( \lambda(h) \) equal the marginal price \( \rho(h) \), or equivalently, the marginal costs of the unit of generation exactly equal the marginal benefits of the unit of consumption.

- This fundamental result in marginal costing is the reason for the efficiency [optimality] of marginal-cost-based prices.
- We make use of this important result throughout our analysis.
HOURLY VARIABLE COSTS

For hour \( h \),

\[
V(h) = \mathcal{E}_s[\ell(h)] + \mathcal{E}_o[\ell(h)]
\]

where

\[
\mathcal{E}_s[\ell(h)] = \text{costs of supplying demand } \ell(h)
\]

\[
\mathcal{E}_o[\ell(h)] = \text{costs of unserved energy at } \ell(h)
\]

\( \mathcal{E}_s[\ell(h)] \) is the production costs of serving the load for the hour \( h \)

HOURLY VARIABLE COSTS

\( \mathcal{E}_o[\ell(h)] \) is related to the costs of customer outages; typically, we associate a cost per unit of customer outage of \( \hat{q} \text{$/MWh}$ so that

\[
\mathcal{E}_o[\ell(h)] = \hat{q} \mathcal{U}[\ell(h)]
\]

where \( \mathcal{U}[\ell(h)] \) is the expected unserved energy in hour \( h \)
MARGINAL COSTS

- The two components of the variable costs give rise to two components of marginal costs.

- The definition of marginal costs is

\[
M(h) = \frac{\partial V(h)}{\partial \ell(h)} = \frac{\partial c_s[\ell(h)]}{\partial \ell(h)} + \frac{\partial c_o[\ell(h)]}{\partial \ell(h)}
\]

so that

\[
M(h) = M^e(h) + M^c(h)
\]

In words:

- Hourly marginal costs = Hourly marginal energy costs + Hourly marginal capacity costs

- The interpretation of the first component \(M^e(h)\) is the marginal costs of serving the last unit of energy at the load level \(\ell(h)\).
MARGINAL COSTS

- The interpretation of the second component

\[ M^c(h) \] is the marginal costs of outage caused by capacity shortage with the value given by

\[ \frac{\partial C_o}{\partial \ell} = \hat{q} \frac{\partial U}{\partial [\ell(h)']} \]

- Capacity plays a key role in the definition of both marginal costs

COMPUTATION OF \( M^e(h) \)

- We consider \( C_s[\ell(h)] \), the expected costs of serving the load demand \( \ell(h) MW \) over the hour \( h \)

- We evaluate \( C_s[\ell(h)] \) by computing the expected energy costs to meet the demand of the "flat" LDC of load level \( \ell(h) \) of one hour duration
COMPUTATION OF $M^e(h)$

By varying the load level $\ell$ we can construct the function $c_s(\cdot)$ of the load $\ell$.
COMPUTATION OF $M^e(h)$

- Since $M^e(h)$ is the partial of $C_s(\cdot)$ with respect to $\ell$, $M^e(h)$ is therefore the slope of the tangent line at $\ell(h)$.

$$M^e(h) = \lim_{\Delta \to 0} \frac{C_s[\ell(h) + \Delta] - C_s[\ell(h)]}{\Delta}$$

COMPUTATION OF $M^e(h)$

$$\approx \underbrace{C_s[\ell(h) + 1]} - \underbrace{C_s[\ell(h)]}$$ obtained by letting

the change in the variable costs of supplying the last unit of energy at the load level $\ell(h)$

obtained by letting $\Delta = 1 \text{ MW}$
We adopt, thus, the following definition for $M^e(h)$:
The marginal energy costs at load level $\ell(h)$, $M^e(h)$, are the expected costs per MWh of serving the $\ell(h)^{th}$ MWh of demand at the load level $\ell(h)$ in the hour $h$.

We now introduce two assumptions we make use of in computing $M^e(h)$ by the production costing procedure:

- **A1** – uniform marginal costs of energy: for the specified simulation period, the marginal costs of energy at a given load level $\ell$ are the same at each hour in the period that the load attains this level.
- **A2** – no multi-period dependence: a small change in the load in hour $h$ has no impact on the system behavior in hour $h' \neq h$.
CHRONOLOGICAL LOAD

Load level $\ell(h)$

Monday Tuesday Wednesday Thursday Friday Saturday Sunday

MW

LDC

MW

168

0

1
ASSUMPTION $A_1$

- Assumption $A_1$ is reasonable given that in the $LDC$, the identity of each individual hour that gives rise to a particular load level $\ell$ is unknown.
- The assumption allows the evaluation of the marginal costs of energy at the load level $\ell$ rather than at a particular hour.
- The hours at which the load attains level $\ell$ may be identified by using the chronological load information.

ASSUMPTION $A_2$

- In the $LDC$-based model, the loading order determined for the entire simulation period holds uniformly for each hour of the period: in particular, it holds for each hour of the period during which the load level is $\ell$ and the assumption $A_2$ permits the use of this loading order for the “flat” $LDC$ computations for different values of $\ell$. 
ASSUMPTION $A_2$

- This assumption localizes the cause and effect to the specific hour of interest: a small change in the load $\ell$ in hour $h$ cannot impact the system by changing either the commitment or the loading order in the entire simulation period to which this hour $h$ belongs.

IMPLICATIONS OF ASSUMPTIONS $A_1$ AND $A_2$

- For each load level $\ell$ in the LDC, $M^e(\ell)$ is evaluated using the same loading order.

- In the “flat” LDC for the load level $\ell$, the costs $C_s(\ell)$ are computed with the loading order used for the entire simulation period.

- The key practical implication is that we evaluate $M^e(h)$ from the $M^e(\ell)$ for the different load levels $\ell$. 
EVALUATION OF $M^e(\ell)$

- We use the definition

$$M^e(\ell) = E \left\{ \begin{array}{l} \text{costs / MWh of generation of the } \ell^{th} \\ \text{MWh of demand at the load level } \ell \end{array} \right\}$$

$$= \sum_{i=1}^{N} \left[ \text{costs per unit of energy of block } i \right] \cdot \left\{ \begin{array}{l} \text{block } i \text{ serves the } \ell^{th} \text{ MWh of demand at the load level } \ell \end{array} \right\} \cdot a_i \cdot z_i(\ell)$$

where, $N$ is the total number of supply system blocks.

EVALUATION OF $M^e(\ell)$

- The evaluation of $z_i(\ell)$ is straightforward since

the $z_i(\ell)$ are available from production costing without any additional effort required

$$z_i(\ell) = P \left\{ \begin{array}{l} \text{block } i \text{ serves the } \ell^{th} \text{ MWh of demand at the load level } \ell \end{array} \right\}$$

$$= P \left\{ \begin{array}{l} \sum_{j=1}^{i-1} A_j < \ell \quad \text{and} \quad \sum_{j=1}^{i} A_j \geq \ell \end{array} \right\}$$
EVALUATION OF $M^e(\ell)$

\[
\begin{align*}
1 - P \left\{ \sum_{j=1}^{i-1} A_j \geq \ell \text{ or } \sum_{j=1}^{i} A_j < \ell \right\} \\
= 1 - P \left\{ \sum_{j=1}^{i-1} A_j \geq \ell \right\} - P \left\{ \sum_{j=1}^{i} A_j < \ell \right\} \\
&= P \left\{ \sum_{j=1}^{i-1} A_j < \ell \right\} - P \left\{ \sum_{j=1}^{i} A_j < \ell \right\}
\end{align*}
\]

disjoint events

data obtained from the capacity outage or the capacity availability tables

THE "FLAT" LDC

- The "flat" LDC at load level $\ell$ corresponds to the event $L = \ell$ with probability 1

- The inverted LDC is therefore

\[
\mathcal{L}_o[x; \ell] = \begin{cases} 
1 & x < \ell \\
0 & x \geq \ell 
\end{cases}
\]
We consider the IELDC for the load level $\ell$ after loading the supply blocks $1, 2, \ldots, i$

$$\mathcal{L}_i [x; \ell] = P \left\{ L + \sum_{v=1}^{i} \left( c_v - A_v \right) > x \right\}$$

$$= P \left\{ \sum_{v=1}^{i} A_v < \ell + \sum_{v=1}^{i} c_v - x \right\}$$
THE INVERTED “FLAT” LDC ANALYSIS

Now,

\[
P\left\{ \sum_{v=1}^{i} A_v < \ell \right\} = P\left\{ \sum_{v=1}^{i} A_v < \ell + \sum_{v=1}^{i} c_v - \sum_{v=1}^{i} c_v \right\} = \mathcal{L}_i \left[ \sum_{v=1}^{i} c_v; \ell \right] = \mathcal{L}_i \left[ C_i; \ell \right]
\]

Therefore

\[
z_i(\ell) = P\left\{ \sum_{j=1}^{i-1} A_j < \ell \right\} - P\left\{ \sum_{j=1}^{i} A_j < \ell \right\} = \mathcal{L}_{i-1} \left[ C_{i-1}; \ell \right] - \mathcal{L}_i \left[ C_i; \ell \right]
\]

For any \( i \geq \theta \) and any \( \ell' \) and \( \ell \) we compute

\[
\mathcal{L}_i \left[ x; \ell' \right] \text{ using}
\]
THE \textit{INVERTED} \textit{“FLAT” LDC}
\textbf{ANALYSIS}

\begin{align*}
\mathcal{L}_i \big[ x; \ell' \big] &= P \left\{ \sum_{v=1}^{i} A_v < \ell' + C_i - x \right\} \\
&= P \left\{ \sum_{v=1}^{i} A_v < \ell + C_i - x + \ell - \ell \right\} \\
&= P \left\{ \sum_{v=1}^{i} A_v < \ell + C_i - \left[ x - (\ell' - \ell) \right] \right\} \\
&= \mathcal{L}_i \big[ x - (\ell' - \ell); \ell \big]
\end{align*}

\begin{center}
\textbf{IMPORTANT PROPERTY OF} \ \mathcal{L}_i \big[ \cdot; \ell \big]
\end{center}

\begin{itemize}
\item We derived the expression for the important translation property of \( \mathcal{L}_i \big[ \cdot; \cdot \big] \)
\end{itemize}

\begin{align*}
\mathcal{L}_i \big[ x; \ell' \big] &= \mathcal{L}_i \big[ x - (\ell' - \ell); \ell \big]
\end{align*}

\begin{itemize}
\item Therefore, we need to evaluate \( \mathcal{L}_i [x; \ell] \) for any 
\[ i \geq 0 \]
only for a single value of \( \ell \) and obtain
\end{itemize}

\begin{itemize}
\item \( \mathcal{L}_i [x; \ell'] \) for each value \( \ell' \neq \ell \) by means of the above translation property
\end{itemize}
THE FACTORS $a_i$

- The value of $a_i$ depends on the type of unit to which the block $i$ belongs:
  - thermal unit: $a_i = \text{per unit costs of block } i$
  - hydro unit: $a_i = \text{per unit costs of displaced block} \quad \begin{cases} \text{belonging to the thermal unit loaded immediately after the hydro unit loading point} \end{cases}$
- Energy storage unit: $a_i = \text{per unit costs of displaced block} \quad \begin{cases} \text{belonging to the thermal unit loaded immediately after the storage unit loading point} \end{cases}$

- The definitions above use incremental costs for the $a_i$ factors; an alternative that may result in different values is the choice of decremental costs.
THE FACTORS $a_i$ FOR DECREMENTAL COSTS

- **thermal unit**: $a_i = \text{decremental costs per unit of block } i$

- **hydro unit**: $a_i = \text{per unit costs of thermal block loaded immediately preceding the hydro unit loading point}$

THE FACTORS $a_i$ FOR DECREMENTAL COSTS

- **energy** $a_i = \max\{a_i^t, a_i^c\}$
  
  - **storage** $a_i^t = \text{per unit costs of the thermal plant unit immediately preceding the loading point of storage plant } i$
  
  - $a_i^c = \text{effective per unit costs of charging the energy storage unit}$
We have now shown how to evaluate the $a_i$ factors and the $z_i(\ell)$ terms.

It follows that since more than one block may serve the last $MWh$ of demand at the load level $\ell$,

$$M^e(\ell) = \mathbb{E} \begin{cases} \text{per MWh costs of supplying the} \\ \text{last MWh of demand at load level } \ell \end{cases}$$

The meaning of $M^e(\ell)$ is the expected costs of generation per $MWh$ to serve the last $MWh$ of system demand at the load level $\ell$. 

**THE MEANING OF $M^e(\ell)$**

- **load MW**: $\ell$
- **interpretation of $M^e(\ell)$**: is the expected costs of generation per $MWh$ to serve the last $MWh$ of system demand at the load level $\ell$
- **$0$, $\psi$, $100\%$**
THE \( M^e(\ell) \) EVALUATION

- In the probabilistic framework, there may be more than one marginal unit: we stop referring to “the marginal unit” since more than one unit has a nonzero probability of serving the last \( MWh \) of demand at a specified load level.

COMPUTATION PROCEDURE FOR \( M^e(h) \)

- We provide two approaches for the evaluation of hourly marginal energy costs:
  - \( LDC \) – based interpolation scheme
  - block-differencing scheme
- The \( LDC \) – based scheme allows the determination of the \( M^e(h) \) with a controllable resolution level.
- The differencing scheme is a “large-signal” approach using large blocks of capacity.
**LDC–BASED INTERPOLATION SCHEME**

**Step 1:** Construct a grid on the percentage of time coordinate resulting in a subdivision of the time dimension into the \((\tau + 1)\) LDC factors:

\[ \theta = \psi_0 < \psi_1 < \ldots < \psi_\tau = 1 \]

**Step 2:** Corresponding to each LDC factor \(\psi_i\), determine the load level \(\ell_i\) from the relationship

\[ \mathcal{L}_0(\ell_i) = \psi_i, \quad i = 0, 1, \ldots, \tau \]

**Step 3:** For a given value of load \(\ell\), determine the interval \([\psi_{j-1}, \psi_j]\) such that \(\ell \in [\ell_j, \ell_{j-1}]\)

**Step 4:** Determine the interpolation factors \(\alpha(\ell)\) and \(\beta(\ell)\) to express

\[ \ell = \alpha(\ell) \ell_j + \beta(\ell) \ell_{j-1} \]
Step 5: Compute the marginal costs using the interpolation factors $\alpha(\ell)$ and $\beta(\ell)$:

$$M^e(\ell) = \alpha(\ell) M^e(\ell_j) + \beta(\ell) M^e(\ell_{j-1})$$

Step 6: If there are no other values of $\ell$ specified, stop; else go to Step 3
 COMMENTS ON THE *LDC*-BASED SCHEME

☐ This scheme uses straightforward linear interpolation to determine $M^e(\ell)$ at any load level $\ell$.

☐ The $M^e(\ell)$ computed by this scheme includes:
   - incremental fuel costs
   - variable O&M costs
   - emission costs

 COMMENTS ON THE *LDC*-BASED SCHEME

☐ The $M^e(\ell)$ computed by this scheme does not, however, include unit commitment costs:
   - start-up costs
   - *no-load* fuel costs

☐ The basic assumption is that the change in load is sufficiently small so as not to require redispatch.
The block-differencing schemes provide approximations to the $M^e(\ell)$ of interest by using the results of two distinct production simulation runs to compute the difference in production costs at the two different load levels $\ell$ and $\ell + \Delta \ell$, where $\Delta \ell$ is the block size. $\Delta \ell$ need no longer represent a small – signal change.

The change in production costs is computed

$$\Delta C = C(\ell + \Delta \ell) - C(\ell)$$

The change in energy production is

$$\Delta E = E(\ell + \Delta \ell) - E(\ell)$$

We approximate $M^e(\ell)$ by

$$M^e(\ell) = \frac{\Delta E}{\Delta C} = \frac{\Delta \text{ total production costs (}$\$\text{)}}{\Delta \text{ energy production (MWh)}}$$
THE BLOCK – DIFFERENCING SCHEMES

- The load is changed by a specified amount $\Delta \ell$ in each hour of the simulation period.
  
  \[ \Delta \delta = (\Delta \ell)T \]

- The average of the load increment ($\Delta \ell > 0$) and the load decrement ($\Delta \ell < 0$) changes in costs gives the value of $M^e(\ell)$

HOURLY IMPACT OF LOAD CHANGES

- Load increment and decrement for different resources over time.
- Base case vs. load change cases.
The scheme computes the average of the production cost changes of the load increment and the load decrement cases.

For the load increment case, resource \((i + 3)\) must be dispatched while for the load decrement, resource \((i + 3)\) and portion of resource \((i + 2)\) are not needed.

The differencing scheme captures the costs of committing and starting up resource \((i + 3)\).

The differencing scheme may be extended to evaluate the impact of a particular resource.

The basic idea is to replace the load increment or decrement by a change in the supply-side resource mix and evaluate the production costs with and without a particular resource.

This version of the differencing scheme is sometimes referred to as the in / out scheme.
The production simulation reflects the economic dispatch of the system so that, in general, as the load increases, the cost per \( MWh \) to meet the last \( MWh \) of the load demand becomes higher; in other words, the marginal energy costs increase as the load increases.
The removal of the block of resource 2 from the loading order and its replacement by a more expensive generation resource 3 block causes the total production costs in the “out” case to be higher than in the “in” case; consequently, the marginal costs in the “out” case are above those in the “in” case.

MARGINAL ENERGY COSTS AND MONTHLY PEAK LOADS
We showed that

\[ M(h) = M^e(h) + M^c(h) \]

and we discussed the evaluation of \( M^c(h) \).

For the evaluation of \( M^c(h) \), we start with the costs of the outage term

\[ \mathcal{C}_o \left[ \ell(h) \right] \triangleq \hat{q} \frac{\partial \mathcal{U}}{\partial \ell(h)} \]

where

\[ \hat{q} \triangleq \text{“value of capacity” term expressing the costs of customer outages (S/MWh)} \]

Therefore

\[ M^c(h) = \hat{q} \frac{\partial \mathcal{U}}{\partial \ell(h)} \]
Recall that we express $\mathcal{U}(\ell)$ as the expected unserved energy at load level $\ell$

$$\mathcal{U}(\ell) = T \int_{C_N}^{\infty} \mathcal{L}_N \left[ x + \ell' - \ell ; \ell' \right] dx$$

It follows that

$$\frac{\partial \mathcal{U}(\ell)}{\partial \ell} = T \int_{C_N}^{\infty} \frac{\partial}{\partial \ell} \mathcal{L}_N \left[ x + \ell' - \ell ; \ell' \right] dx$$

$$= T \int_{C_N}^{\infty} - \frac{\partial}{\partial x} \mathcal{L}_N \left[ x + \ell' - \ell ; \ell' \right] dx$$

$$= -T \mathcal{L}_N \left[ x + \ell' - \ell ; \ell' \right]_{C_N}^{\infty}$$

$$= T \mathcal{L}_N \left[ C_N + \ell' - \ell ; \ell' \right]$$

$$= T \mathcal{L}_N \left[ C_N ; \ell \right]$$

$$= \text{LOLP}(\ell) \cdot T$$
We have shown that the marginal costs of capacity for a given load level $\ell$ is a function of the $LOLP(\ell)$ and $\hat{q}$ which we view as some factor that gives an indication of the value of capacity:

$$M^c(\ell) = f(LOLP, \hat{q})$$

$$= f(\text{reliability, "value of capacity"})$$

The basis for determining the “value of capacity” is, typically, the capacity costs of a combustion turbine $(CT)$.

For example, it is possible to define an energy reliability index or $ERI$ as

$$ERI = \frac{\text{actual reliability}}{\text{reference reliability}}$$

and then define

$$\hat{q} \triangleq ERI \cdot CT \text{ costs}$$
COMPUTATION OF $M^c(h)$

- Two possible choices for ERI are
  - the ratio of actual LOLP to the standard of 1 day in 10 years LOLP:
    \[
    \frac{\text{LOLP (actual)}}{\text{LOLP of 1 day in 10 years}}
    \]
  - the ratio of the customer outage costs to the CT costs:
    \[
    \frac{\text{customer outage costs}}{\text{CT costs}}
    \]

MARGINAL CAPACITY COSTS

- $$/kW\text{-year}$
- "value of capacity"
- $CT$ costs
MARGINAL CAPACITY COSTS

FACTORS INFLUENCING MARGINAL COSTS

- Load
- Resource mix
- Maintenance schedule
- Unit commitment and scheduling
- Operating constraints (e.g., fuel emission limitations, area protection requirements)
FACTORS INFLUENCING MARGINAL COSTS

- Available generating capacity (outage rates, capacity states, hydro conditions, purchased power availability)
- Costs of fuels
- O&M costs
- Emission costs

TYPICAL APPLICATIONS OF MARGINAL COSTS

- Determination of avoided costs for QF and cogeneration power pricing
- Cost effectiveness of conservation and load management programs
- Cost effectiveness analyses of generation, transmission, and distribution facilities
- Long-term resource planning
- Power sale/purchase contract evaluations
A SIMPLE COST-EFFECTIVENESS TEST

- Conservation programs are economic as long as the payments per unit of electricity saved are no greater than the difference between marginal costs and the average costs.

- Marketing efforts for additional sales of electricity are economic as long as the marginal costs are below the average costs.