Topic 1A-ii: Resource adequacy

START HERE, SLIDE 12.

Resource adequacy is the ability of supply-side and demand-side resources to meet the aggregate electrical demand (including losses).

Resource adequacy is quantified using loss-of-load probability (LOLP), loss of load expectation (LOLE), and expected energy not served (EENS):

- LOLE is the number of time units that the load will exceed the capacity.
- LOLP is the probability that the load will be interrupted during a given time period.
- EENS is expected energy not served during a given time period.

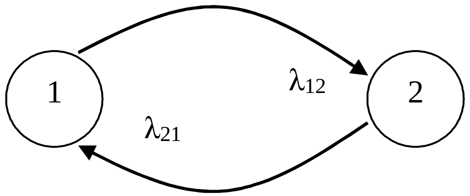
A very widely-quoted threshold (maximum) value for LOLE is “1 day in 10 years” which means that during a period of 10 years (87,600) hours, the power system is expected to interrupt load for 24 of those hours (1 day). It can also be expressed as 0.1 days per year.

There are software applications to compute LOLE for large-scale power systems, e.g., GEMARS, PRISM, SERVM; most use Monte Carlo simulation, convolution, or network flows.

Capacity markets, which exist at four RTOs (NYISO, ISONE, PJM, and MISO), are built on resource adequacy calculations. At MISO, the capacity market is called the planning resource auction (PRA).

Markov Models

State 1: Up;
State 2: Down.



λ_{jk}: # of transitions per unit time from state j to state k.

λ_j: # of transitions per unit time from state j to any other state.

$$\lambda_j = \sum_{j \neq k} \lambda_{jk}$$

Transition intensity matrix: $$\underline{A} = \begin{bmatrix} -\lambda_1 & \lambda_{12} \\ \lambda_{21} & -\lambda_2 \end{bmatrix}$$

Define p(t) as the vector of state probabilities, i.e.,

$$\underline{p}(t) = \begin{bmatrix} p_1(t) & p_2(t) \end{bmatrix}$$

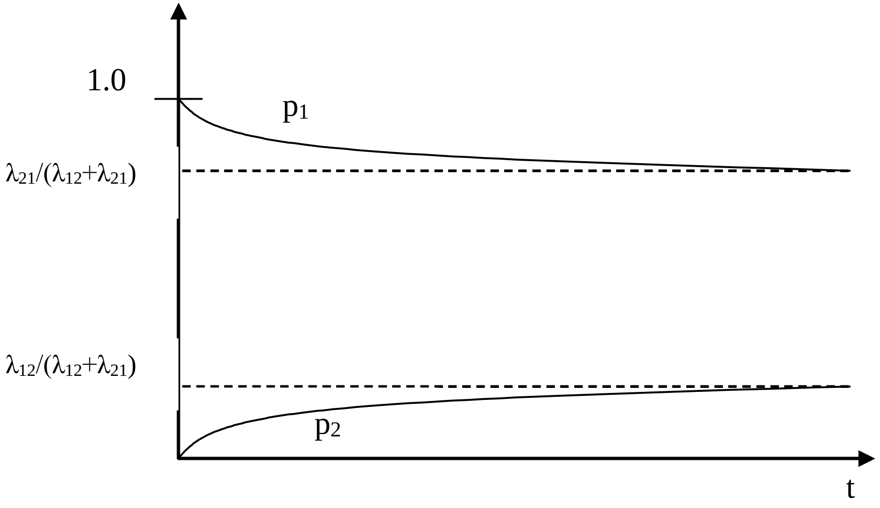
It is possible to show (see U16 notes) that

$$\dot{\underline{p}}(t) = \underline{p}(t)\underline{A}$$

The long-run (steady-state) probabilities may be found by setting the left-hand-side derivatives to 0, and (because A is singular), replacing one equation in A with the sum of all steady-state probabilities=1, in this case, $p_1+p_2=1$. This results in:

$$p_1 = \frac{\lambda_{21}}{\lambda_{12} + \lambda_{21}}; \qquad p_2 = \frac{\lambda_{12}}{\lambda_{12} + \lambda_{21}}$$

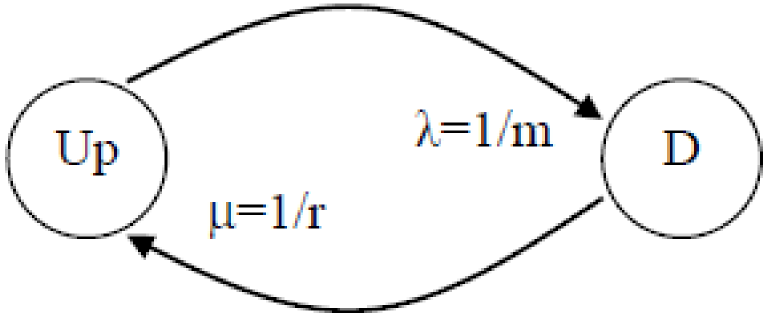
The relation of the steady-state probabilities to the general time-domain expressions is illustrated in the figure below. This figure assumes that the initial condition of the system is that it is in state 1, i.e., it is in the "up" (working) condition.



In most of our work, we will want the steady-state probabilities. For long-term planning studies, we may interpret a particular long-run state probability as the percentage of the planning horizon time that the system can be expected to reside in the corresponding state.

Resource adequacy – Forced Outage Rate

A generator may be represented by a 2-state Markov model, shown below.



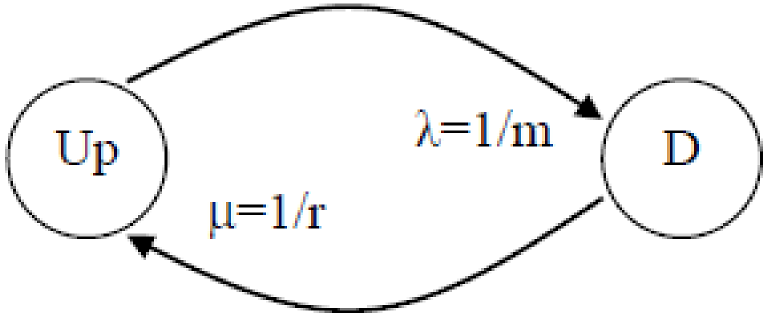
In this model, λ is the failure rate of the generator with units of number of failures per year, and μ is the repair rate with units of number of repairs per year.

These parameters may be found by computing the mean of the time to failures (MTTF) and the mean of the time to repair (MTTR), from which we obtain $\lambda=1/MTTF$ and $\mu=1/MTTR$.

More generally, λ and μ are referred to as transition rates.

The system is said to be Markov if it is memoryless, i.e., if the probability of future events depends only on information characterizing the present and not on any information characterizing the past; the amount of time it spends in each state is exponentially distributed; and the states are mutually exclusive (the process cannot reside in two or more states simultaneously).

Resource adequacy – Forced Outage Rate



We show in the notes of U16 (see section U16.5)that the long-run (steady-state) probabilities of residing in the "up" and "down" states are given by:

$$A = \frac{\mu}{\lambda + \mu}; \qquad U = \frac{\lambda}{\lambda + \mu}$$

U is also called the forced outage rate (FOR) of the generator. For a given extended period of time T in the past, it gives the percent of that time that the unit was out of service. Although it is referred to as a rate, it is treated as a probability, i.e., (assuming the statistics of the future are characterized by the statistics of the past), U=FOR gives the probability at any given time of the unit being in the down state.

Resource adequacy – Capacity Outage Probability Table (COPT)

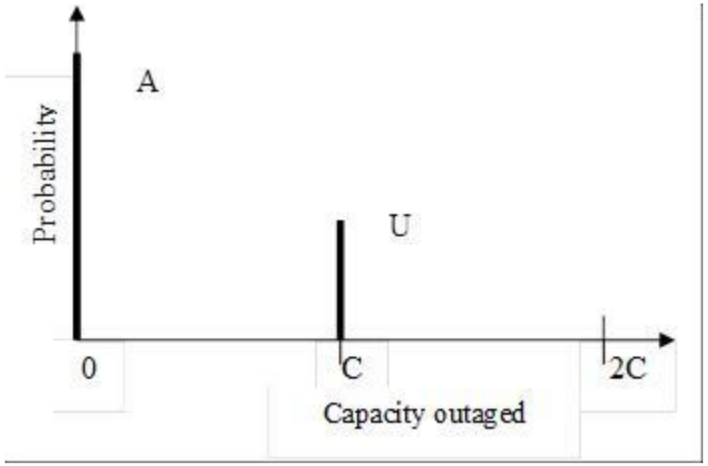
A capacity probability table is a probabilistic description of the possible capacity states of the system being evaluated. The simplest case is that of the 1 unit system, where there are two possible capacity states: 0 and C, where C is the maximum capacity of the unit. The capacity table for this case is given below.

Capacity	Probability
C	A
0	U

We may also describe this system in terms of capacity outage states. Such a description is generally given via a capacity outage probability table (COPT), shown below.

Capacity Outage	Probability
0	A
C	U

The figure below shows the probability mass function (pmf) corresponding to the capacity outage table.



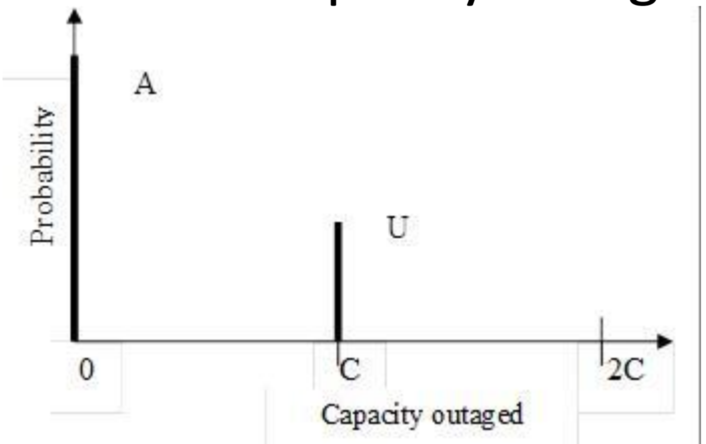
Resource adequacy – Convolution

Now consider a two unit system, with both units of capacity C. We can obtain the COPT by basic reasoning, resulting in:

Capacity Outage	Probability
0	A^2
C	AU
C	UA
2C	U^2

Capacity Outage	Probability
0	A^2
C	2AU
2C	U^2

Define X_1 as the capacity outage random variable (RV) for unit 1 and X_2 as the capacity outage RV for unit 2, with pmfs $f_{X1}(x)$ and $f_{X2}(x)$, each of which appear as the capacity outage pmf below.



We desire $f_Y(y)$, the pmf of Y, where $Y=X_1+X_2$. Recall that we can obtain $f_Y(y)$ by convolving $f_{X1}(x)$ with $f_{X2}(x)$, i.e.,

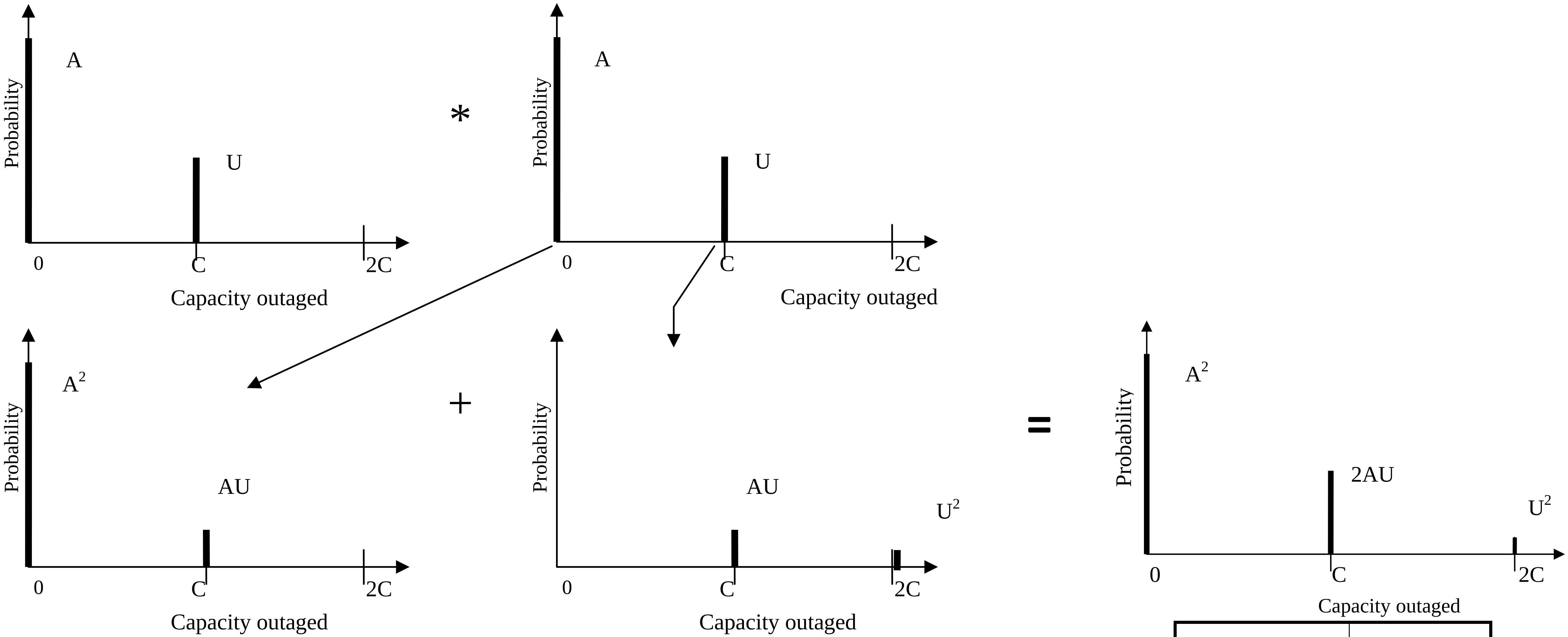
$$f_Y(y) = \int_{-\infty}^{\infty} f_{X1}(x) f_{X2}(y-x)dx$$

Inspection of $f_{X1}(x)$ and $f_{X2}(x)$ indicates their pmfs are comprised of impulses. Convolution of any function with an impulse function simply shifts and scales that function.

- The shift moves the origin of the original function to the location of the impulse;
- The scale is by the value of the impulse.

This enables us to perform the convolution very easily…

Resource adequacy – Convolution

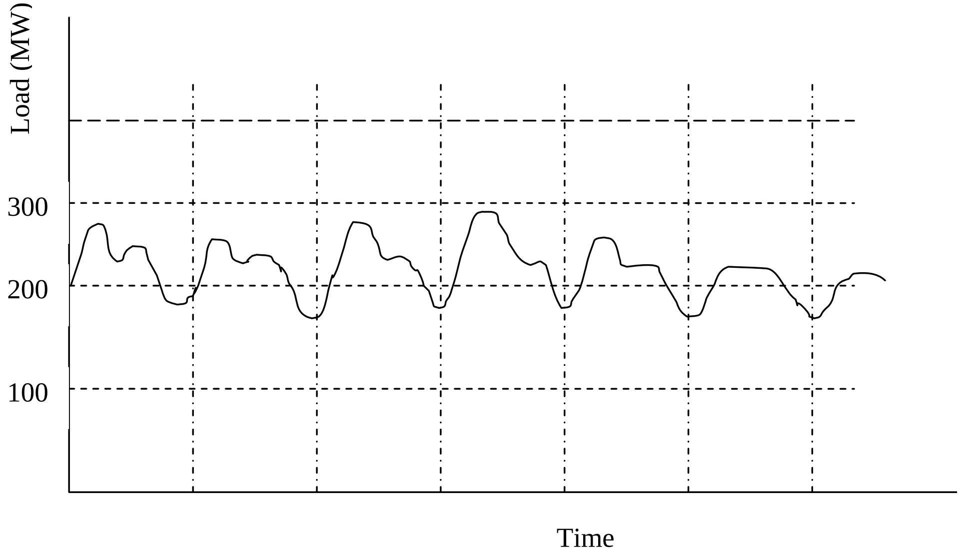


From previous slide➔

Capacity Outage	Probability
0	A^2
C	2AU
2C	U^2

Resource adequacy – Load Characterization

Consider the plot of instantaneous demand as a function of time, as below.



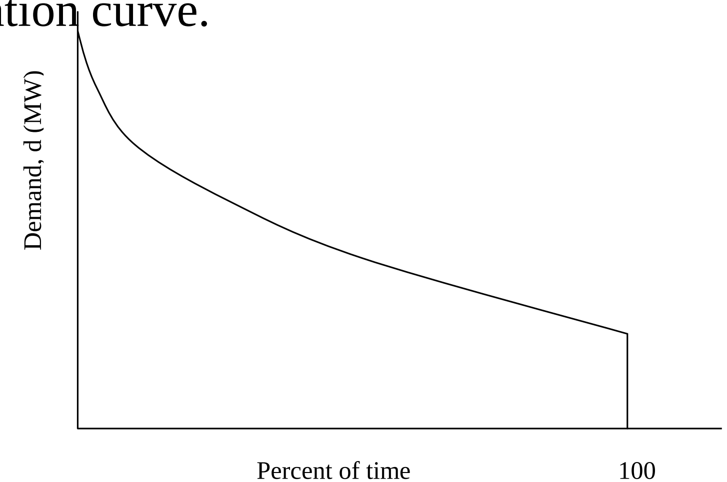
Although this curve is only illustrated for 7 days, one could easily imagine extending the curve to cover a full year.

From such a yearly curve, we may identify the % of time for which the demand exceeds a given value.

If we assume that the curve is a forecasted curve for the next year, then this percentage is equivalent to the probability that the demand will exceed the given value in that year.

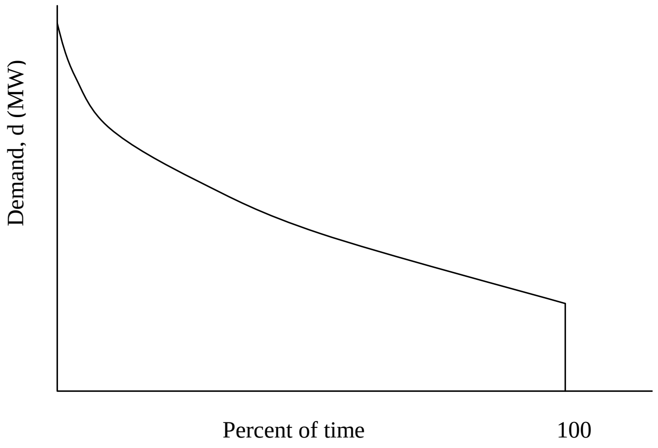
The procedure for obtaining the % of time for which the demand exceeds a given value is as follows.

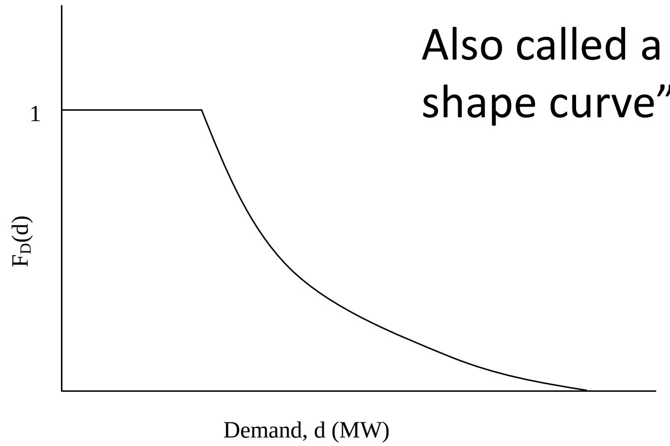
1. Discretize the curve into N equal time segments, so that the value of the discretized curve in each segment takes on the maximum value of the continuous curve in that segment.
2. The percentage of time the demand ***exceeds a value*** d is obtained by counting the number of segments having a value greater than d and dividing by N.
3. Plot the demand d against the percent of time the demand exceeds a value d. A typical such plot is illustrated below; it is called the load duration curve.



Resource adequacy – Load Characterization

We convert the load duration curve to a load model (or cumulative distribution function) by dividing abscissa values (x-axis) by 100, & switching the axes. The result is below.





Also called a “load shape curve”

The ordinate then represents the probability that the demand exceeds the corresponding value *d*. We denote this probability using the notation for a cumulative distribution function (cdf), $F_D(d)$. It is actually the complement of a true cdf, i.e.,

$$F_D(d) = P(D > d) = 1 - P(D \le d)$$

where *D* is a random variable and *d* are values it may take.

Resource adequacy – Load Characterization

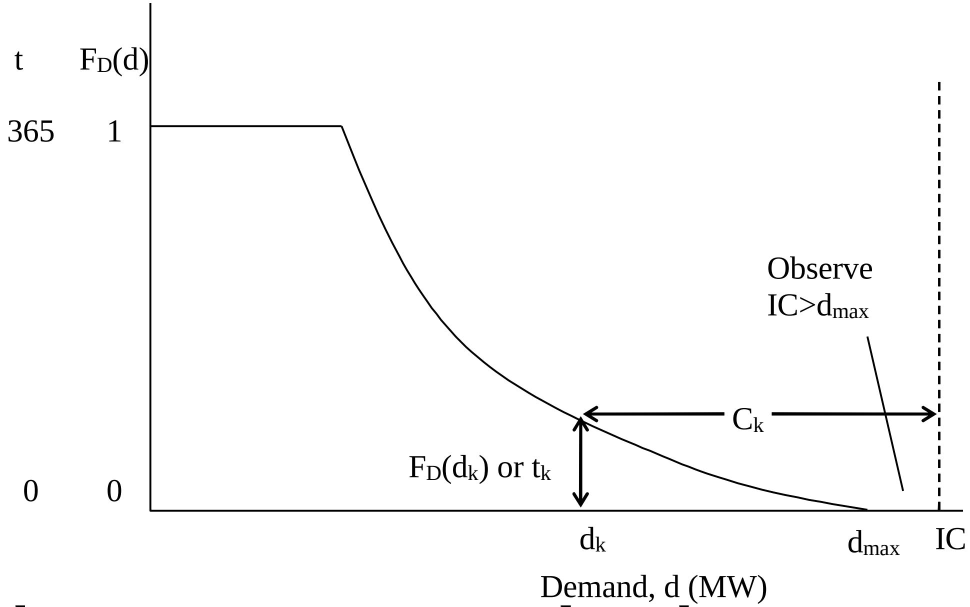
The figure to the right illustrates a typical load-capacity relationship where the load model is shown for a period of T=365 days.

The capacity outage state, C_k, is shown so that one observes that load interruption only occurs under the condition that the load exceeds the installed capacity less the capacity outage, i.e., $d > IC-C_k$. The maximum demand that avoids load interruption is $d_k=IC-C_k$, i.e., load interruption will occur for $d>d_k$.

Thus, the probability of having an outage of capacity C_k and of having the demand exceed d_k is given by the capacity outage pmf and $F_D(d_k)$, i.e.,

$$f_Y(C_k)F_D(d_k)= f_Y(C_k)F_D(IC-C_k).$$

(This assumes independence between outage events & demand).



The LOLP is computed as the sum over all capacity outage states:

$$LOLP = \sum_{k=1}^{N} f_Y(C_k)F_D(IC-C_k)$$

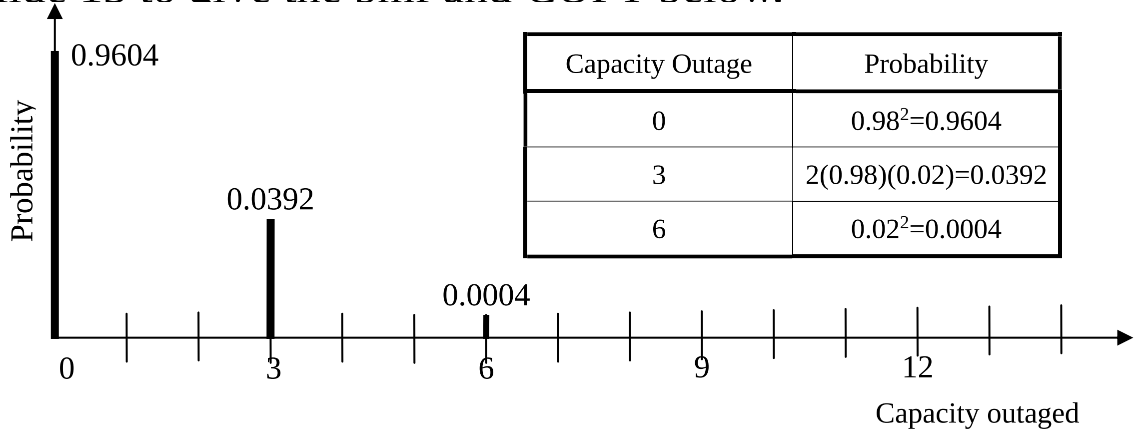
and the LOLE as:

$$LOLE = LOLP \times T = \sum_{k=1}^{N} f_Y(C_k)F_D(IC-C_k)*365 = \sum_{k=1}^{N} f_Y(C_k)t_k$$

where N is the number of capacity outage states and t_k is the amount of time the system is expected to have demand exceeding d_k (illustrated in above figure).

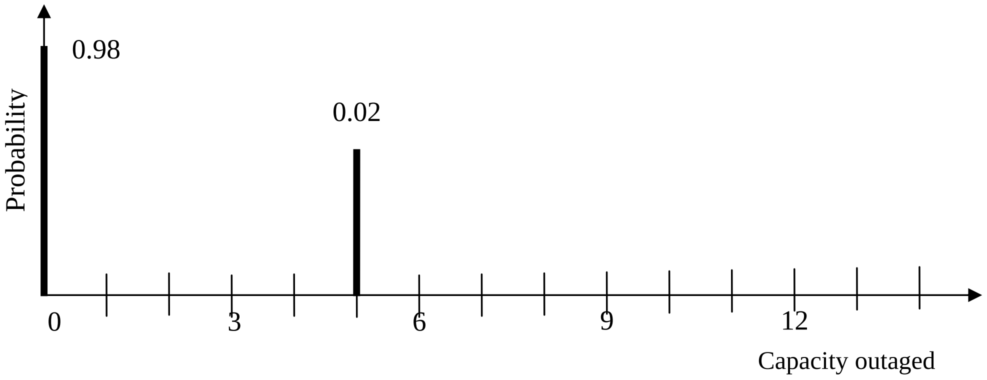
Resource adequacy – Example

Consider a system with two 3 MW units and one 5 MW unit, all of which have forced outage rates (FOR) of 0.02.
The pmfs of the two identical 3 MW units can be convolved as in Slide 13 to give the pmf and COPT below.

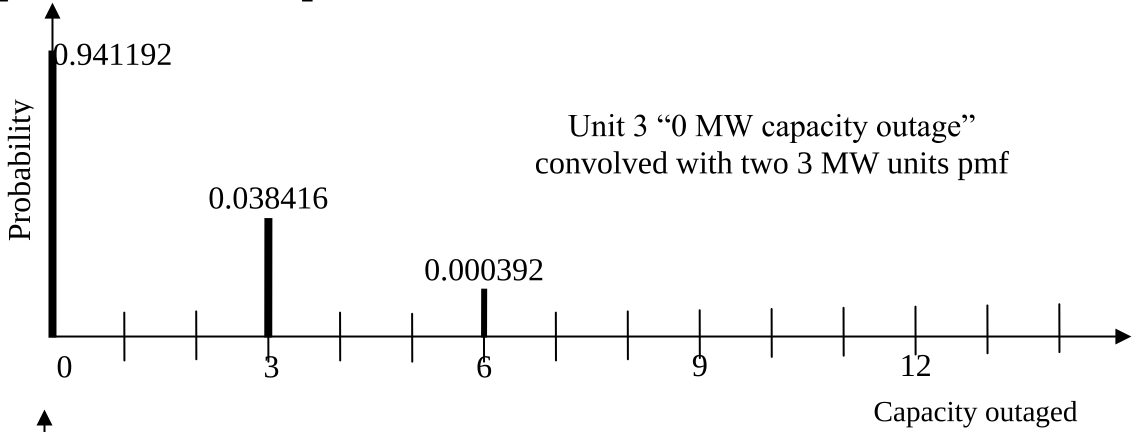


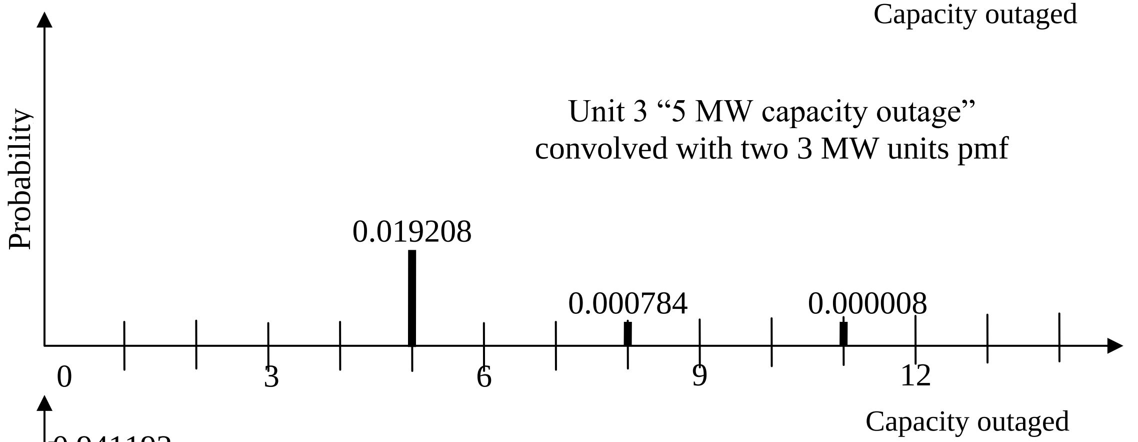
Capacity Outage	Probability
0	0.98^2=0.9604
3	2(0.98)(0.02)=0.0392
6	0.02^2=0.0004

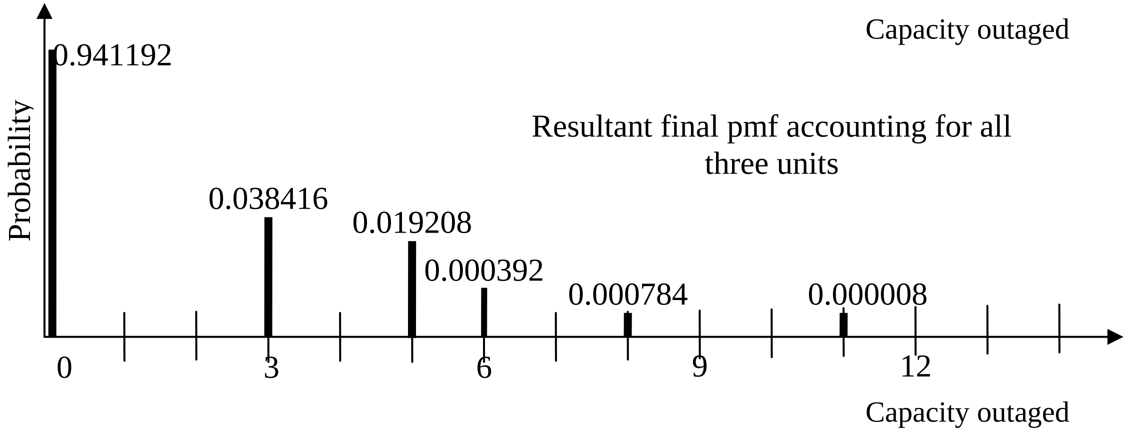
The 5 MW unit (call it "unit 3") has a pmf as below.



Convolving the 5 MW unit's pmf (above) with the two 3 MW units' pmf (above top) results in the below.







The COPT for this appears on the next slide.

Resource adequacy – Example

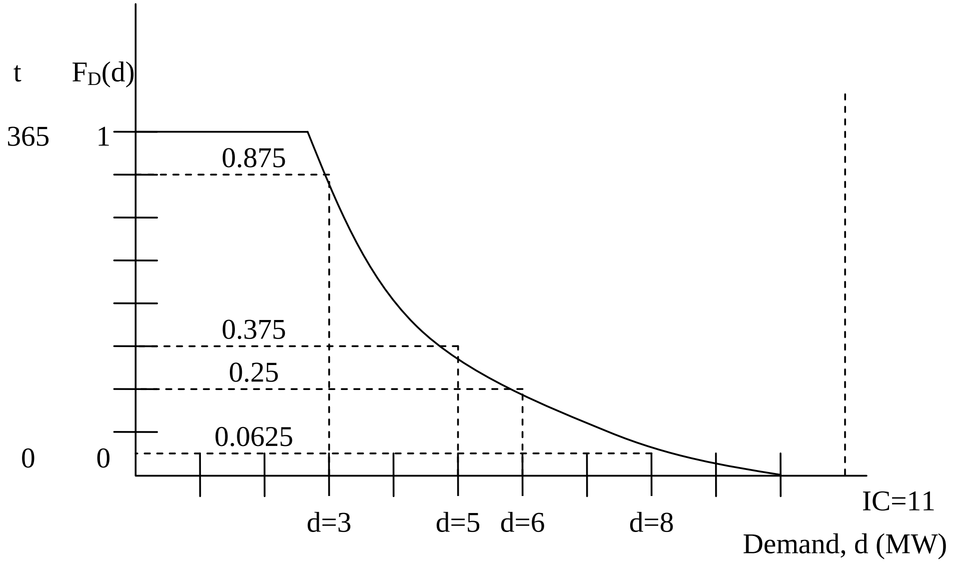
The COPT corresponding to pmf on previous slide:

Capacity Outage	Probability
0	0.98×0.9604=0.941192
3	0.98×0.0392=0.038416
5	0.02×0.9604=0.019208
6	0.98×0.0004=0.000392
8	0.02×0.0392=0.000784
11	0.02×0.0004=0.000008

This table tells us that over a given time interval, the probability that the system will have a capacity outage:

- of 0 MW is 0.941192;
- of 3 MW is 0.038416;
- of 5 MW is 0.019208;
- of 6 MW is 0.000392;
- of 8 MW is 0.000784;
- of 11 MW is 0.000008.

Now consider a system having the below load model:



Using the LOLP expression from slide 20:

$$
\begin{aligned}
LOLP &= \sum_{k=1}^{N} f_Y(C_k)F_D(IC - C_k) \\
&= f_Y(0)F_D(11) + f_Y(3)F_D(8) + f_Y(5)F_D(6) \\
&\quad + f_Y(6)F_D(5) + f_Y(8)F_D(3) + f_Y(11)F_D(0) = \\
&= .941192*0 + .038416*.0625 + .019208*.25 \\
&\quad + .000392*.375 + .000784*.875 + .000008*1 \\
&= 0.008044 / \mathit{year}
\end{aligned}
$$

We could compute LOLE using its expression on slide 20, but now that we have LOLP, it is easier to use:

$$LOLE = LOLP \times T = 0.008044 * 365\text{days} = 2.93606\text{days/year}$$

This is well-above the 0.1days/year that industry requires, and so this reliability level is unacceptable. We should add more capacity to this system. Two qualifiers:

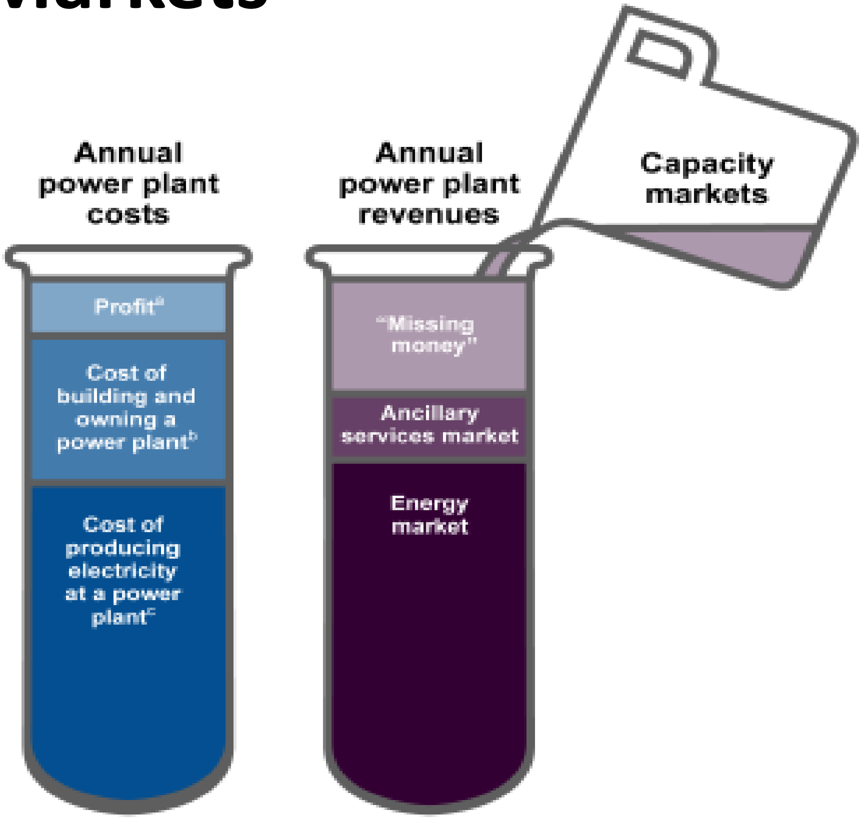
- This LOLE is load outage time expected due to gen unavailability; it doesn't include effects of transm/dist component unavailability.
- This outage time is the long-run average of this system only if
  - all 3 units are always committed, i.e., no reserve shutdown, and there is no maintenance;
  - demand remains constant throughout each time interval

Capacity Markets

The closest thing we have to planning markets today is the capacity market.

The capacity market has been motivated by the "missing money" problem, where

- The real-time market price is capped so that during (rare) very high-stress time periods, prices (and the system) avoids socially-unacceptable performance.
- This results in suppliers not seeing the signal (and money) to build more capacity.
- So "tight" real-time market price-caps are generally coupled with capacity markets to supply that "missing money."



Capacity markets today, where they exist, only address generation capacity. They do not address transmission capacity. Transmission capacity, despite its close interlinkage with generation capacity, is addressed in a separate planning process.

Today's Capacity Markets – World [6]

Appendix A. Overview of CMs

Overview of implemented CRMs around the world. Sources: Bhagwat et al. (2016b), Byers et al. (2018), Cejie (2015), Chow and Brant (2018), Deutscher Bundestag (2016), EirGrid plc and SONI Limited (2017), European Commission (2014, 2016a,b,c, 2017a,b), Government of Western Australia (2017), Hancher et al. (2015), Harbord (2016), Midcontinent Independent System Operator, Inc. (2019), New York Independent System Operator (2018), Patrian (2017), PJM (2018), Roques et al. (2017), Single Electricity Market Committee (2016), Southwest Power Pool, I. (2018a,b), Svenska Kraftnät (2016).

Type	Market area	Administrator		Eligible technologies				Status[1]	
		TSO/ISO	RA	TPP	VRES	DSM	IC		
Strategic reserve	Belgium	x	x	x		x		Active	(2014)
	Germany	x	x	x		x		Planned[2]	(2018)
	Sweden	x		x		x		Active	(2003)
Central buyer	Colombia		x	x	x			Active	(2006)
	Ireland[3]	x	x	x	x	x	x	Planned	(2017)
	Italy[3]	x	x	x		x	x	Planned	(2018)
	Poland[4]	x	x	x	x	x	x	Planned	(2018)
	UK	x	x	x	x	x	x	Active	(2014)
	US – ISO-NE	x		x	x	x	x	Active	(1998)
	US – MISO	x		x	x	x	x	Active	(2009)
	US – NYISO	x		x	x	x	x	Active	(1999)
	US – PJM	x		x	x	x	x	Active	(2007)
De-central obligation	Australia – SWIS	x	x	x	x	x		Active	(2005)
	France	x		x	x	x	x	Active	(2015)
	US – CAISO	x	x	x	x	x	x	Active	(2006)
	US – SPP	x		x	x	x	x	Active	(2018)
Targeted capacity payment	Spain[5]	x		x				Active	(2007)

Abbreviations: CAISO—California ISO, DSM—demand side management, IC—interconnector, ISO—independent system operator, ISO-NE—ISO New England, MISO—Midcontinent ISO, NYISO—New York ISO, PJM—Pennsylvania-New Jersey-Maryland Interconnection, RA—regulatory authority, SPP—Southwest power pool, SWIS—South West interconnected system, TPP—thermal power plant, TSO—transmission system operator, VRES—variable renewable energy sources

[1] Year of (planned) implementation in parentheses. The year refers to the respective mechanism currently in place, however, other mechanism may have been used before.

[2] In Germany, two separate mechanisms have been discussed that can be classified as a strategic reserve. In 2016, a security stand-by arrangement for lignite-fired power plants with a total capacity of 2.7 GW was introduced in order to attain national climate targets. Furthermore, an additional so-called capacity reserve is supposed to be active in winter of 2018/19 to ensure generation adequacy. However, as the European Commission still assesses whether the capacity reserve complies with EU state aid rules, it is unclear whether the planned schedule can be met.

[3] To date, targeted capacity payments are used.

[4] Currently, a strategic reserve is implemented.

[5] This refers to the now in place "availability service" mechanism. An additional mechanism named "investment incentive" was abolished in 2016.

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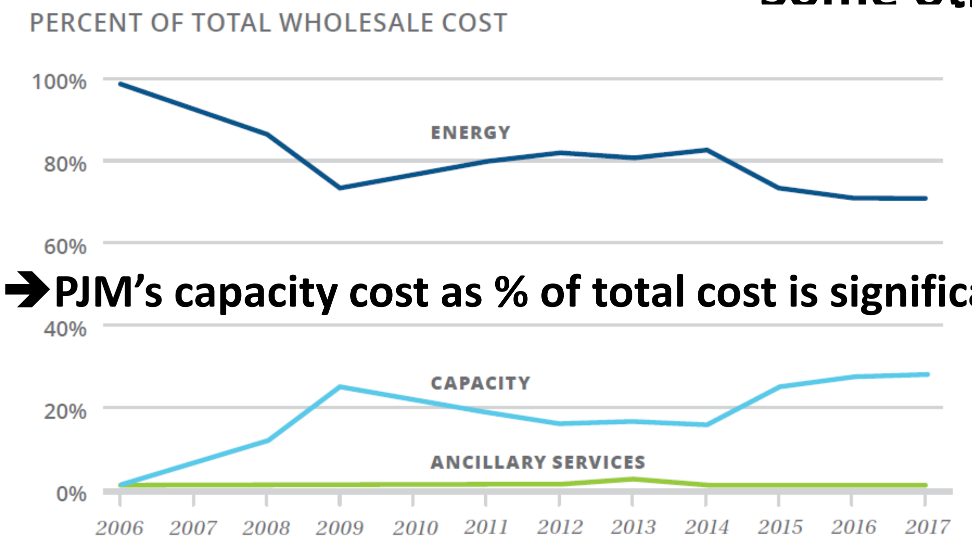
[6] Capacity Procurement Mechanism Significant Event - Intent to Solicit and Designate Capacity; Informational Call 7/2/21, http://www.caiso.com/Documents/CapacityProcurementMechanismSignificantEvent-Intent-Solicit-DesignateCapacity-070121.html. .

Today’s Capacity Markets – US Only

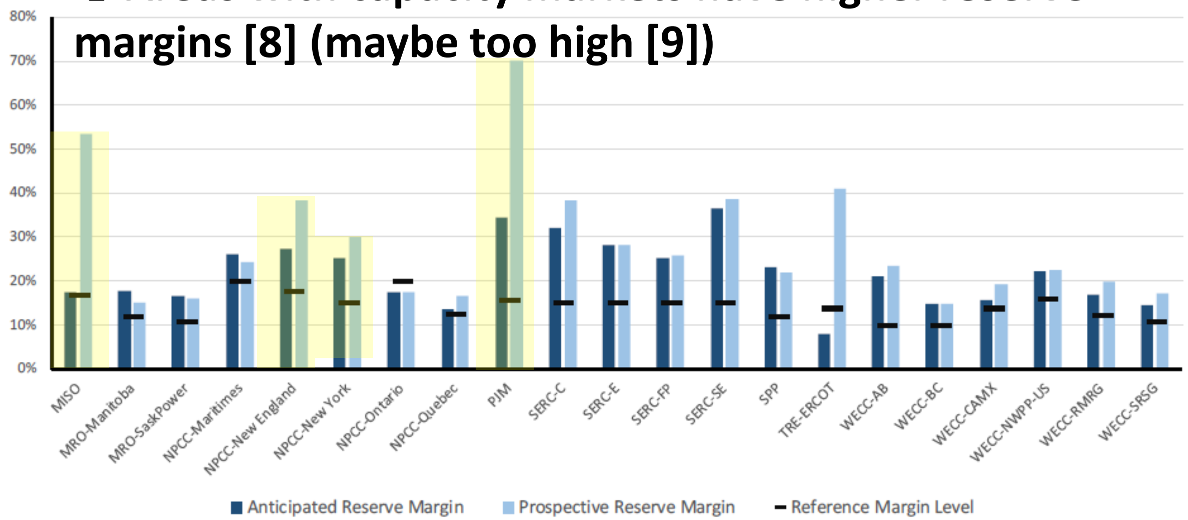
ISO	Cap mrkt	Number of auctions, time before delivery period, and delivery period duration [1] and other info; OR Why they don’t have cap market.	Participants	Recent prices ($/MW-day) [1]
MISO	Yes	Single auction 2 mnths before 1-yr delivery period. OMS says resource adequacy within MISO is state/local responsibility; unlike other Eastern Interconnection RTOs, MISO is composed of traditional vertically-integrated utilities subject to state/local regulation; OMS members have jurisdiction over type/amount of gen constructed within their boundaries by utilities they regulate & costs recovered by those utilities [2]. Also see MISO BPM011 [3].	Existing power plant owners	2 [1] 5, zones1-7; 0, zones 8,9 [X]
NYISO	Yes	Seasonal auction, monthly auction, final auction; from 6 mnths to few days before 1-mnth delivery period	Existing power plant owners	73-328
PJM	Yes	Single auction 3 yrs before 1-yr delivery period	Existing power plant owners and project developers	77-188
ISONE	Yes	Single auction 3 yrs before 1-yr delivery period	Existing power plant owners and project developers	234
CAISO	No	Bringing cap-mrkt in spurred by high wind/solar increase+concern for uneconomic gas units [4], but Cal legislatively-mandated long-term capacity procurement plan [4]. CPUC adopted a Resource Adequacy policy framework in 2004 that includes obligations applicable to all LSEs within CPUC’s jurisdiction. The Commission’s RA policy framework – implemented as the RA program – guides resource procurement and promotes infrastructure investment by requiring that LSEs procure capacity so that capacity is available to the CAISO [7]. Gas may self-schedule to keep their capacity [5]. CAISO can solicit capacity via announcements [6].	NA	NA
ERCOT	No	Enrgy capped $9k/mwh instead of ~$2k in other energy mrkts: scarcity prices provide revenues for cap investment.	NA	NA
SPP	No	LREs are responsible for ensuring they have access to enough generating capacity to meet their load obligations. They must also satisfy planning reserve margin (PRM) obligations to ensure available capacity is sufficient to serve load at times of peak demand. They must demonstrate compliance with these requirements by identifying their owned resources in a submission as required by SPP’s tariff or by procuring the capacity through bilateral contracts [7]. SPP lets coal self-schedule to keep their capacity [5].	NA	NA

[1] US Government Accountability Office, GAO-18-313, “Electricity Markets: Four Regions Use Capacity Markets to Help Ensure Adequate Resources but FERC Has Not Fully Assessed Their Performance,” Dec., 2017, www.gao.gov/assets/690/688811.pdf.
[2] G. Bade, “FERC rejects generator proposal for CAISO capacity market” Utility Dive, Nov. 21, 2018, www.utilitydive.com/news/ferc-rejects-generator-proposal-for-caiso-capacity-market/542833/.
[3] MISO Business Practice Manual BPM11, “Resource Adequacy.” See section 5.5, “Planning Resource Auction.” https://cdn.misoenergy.org//BPM%20011%20-%20Resource%20Adequacy110405.zip.
[4] Organization of MISO States, “State Regulatory Sector Response September Hot Topic on Resource Adequacy,” Sept, 2016, www.misostates.org/images/stories/Filings/HotTopics/2016/Item_7_OMS_Hot_Topic_Comments_FINAL.pdf.
[5] J. Gheorghiu, “Capacity pricing changes: how each power market plans to account for resource adequacy,” Deep Dive, Dec., 2018, https://www.utilitydive.com/news/capacity-pricing-changes-how-each-power-market-plans-to-account-for-resour/542449/
[6] Capacity Procurement Mechanism Significant Event - Intent to Solicit and Designate Capacity; Informational Call 7/2/21, http://www.caiso.com/Documents/CapacityProcurementMechanismSignificantEvent-Intent-Solicit-DesignateCapacity-070121.html.
[7] “Resource adequacy primer for state regulators,” file:///C:/Users/jdm/Downloads/752088A2-1866-DAAC-99FB-6EB5FEA73042%20(1).pdf. .
[X] MISO, “2021/2022 Planning Resource Auction (PRA) Results,” April 15, 2021, https://cdn.misoenergy.org/PY21-22%20Planning%20Resource%20Auction%20Results541166.pdf

Some other info on capacity markets



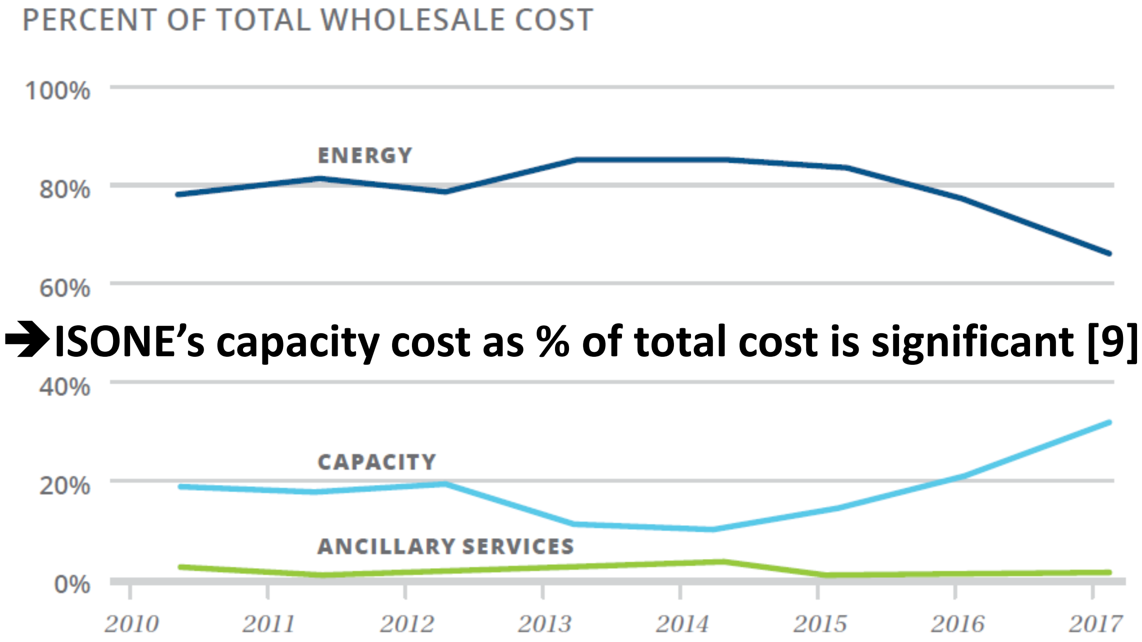
➔PJM's capacity cost as % of total cost is significant [6,9]



➔Areas with capacity markets have higher reserve margins [8] (maybe too high [9])

Pretty certain

Includes anticipated + less certain



➔ISONE's capacity cost as % of total cost is significant [9]

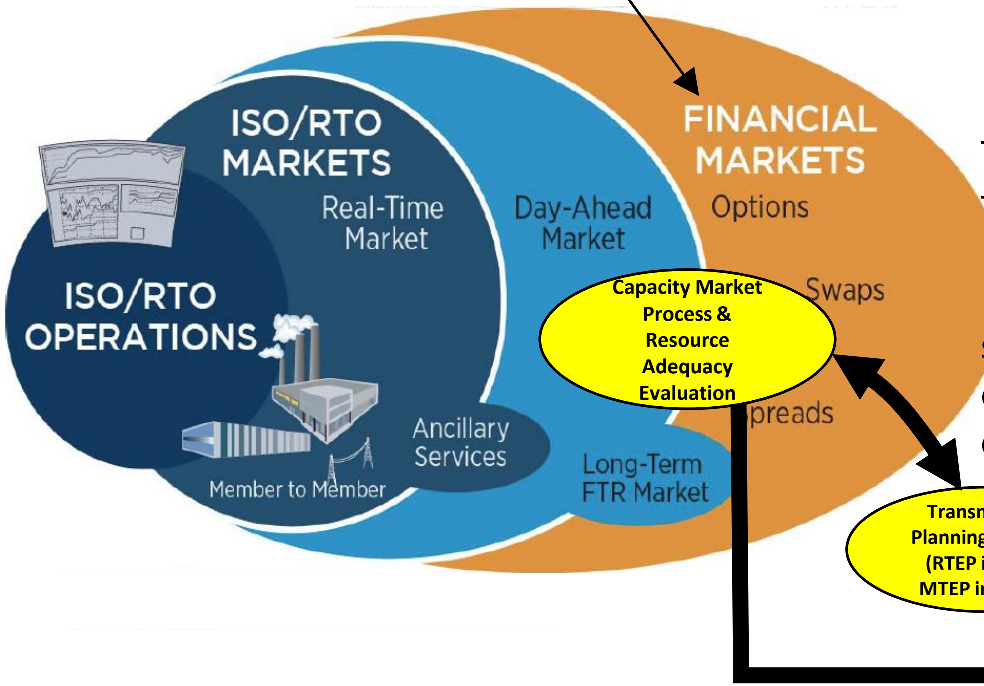
"Beginning in 2016, MISO began experiencing a marked increase in the number of Maximum Generation Emergency (MaxGen) emergencies. As a result, the Resource Availability and Need (RAN) initiative was established to identify near-term solutions to increase the conversion of committed capacity resources into energy during times of need." [10]

[6] Capacity Procurement Mechanism Significant Event - Intent to Solicit and Designate Capacity; Informational Call 7/2/21, http://www.caiso.com/Documents/CapacityProcurementMechanismSignificantEvent-Intent-Solicit-DesignateCapacity-070121.html. .
[8] NERC, "2019 Long-term reliability assessment,", https://www.nerc.com/pa/RAPA/ra/Reliability%20Assessments%20DL/NERC_LTRA_2019.pdf.
[9] M. Goggins, "Capacity Markets: The Way of the Future or the Way of the Past?," March 27, 2020, www.esig.energy/capacity-markets-the-way-of-the-future-or-the-way-of-the-past/#:~:text=Capacity%20markets%20are%20used%20in,several%20years%20in%20the%20future.. .
[10] MISO, "Aligning resource availability and need," Dec., 2019, https://cdn.misoenergy.org/Aligning%20Resource%20Availability%20and%20Need%20(RAN)410587.pdf.

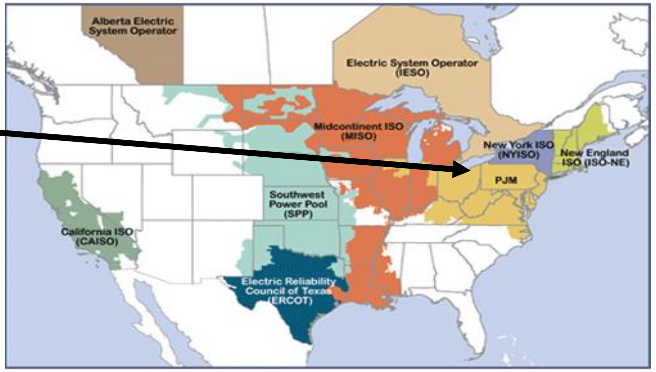
View of Today’s Electricity Market Systems

<u>FINANCIAL MARKETS (a side comment)</u>: “Like other commodities, wholesale electricity is transacted both physically and traded financially. And like other financially traded commodities, specialized environments, such as exchanges and electronic trading platforms, have evolved to facilitate financial trading. For instance, financial electricity is traded on the New York Mercantile Exchange (“NYMEX”), the Intercontinental Exchange (“ICE”) and Nodal Exchange. These exchanges offer futures, options and swaps to trade electricity specific to PJM and at multiple locations (or nodes) on the PJM system. These so-called “secondary markets” in PJM electricity are not regulated by the FERC. They are separate from PJM’s FERC-regulated markets and affect PJM’s markets only very indirectly. While these secondary financial markets are not the subject of today’s hearing, I raise them only to clarify that highly developed, highly liquid and specialized forums exist for those that wish to hedge or speculate on PJM electricity prices outside of the PJM market itself. PJM’s markets are fundamentally designed to facilitate the dispatch, purchase, sale and delivery of physical electricity from power plants to wholesale electricity buyers, who in turn sell retail electricity to homes and businesses.”

- V. Duane, VP Compliance 7 External Relations, PJM, “Examining the role of financial trading in the electricity markets,” Nov. 29, 2017, in testimony to the US House of Representatives Committee on Energy& Commerce/Subcommittee on Energy. www.pjm.com/-/media/library/reports-notices/special-reports/20171129-duane-testimony-to-house-energy-subcommittee-on-financial-trading.ashx.



The picture to the left is for PJM, but other ISOs look similar, with exception of the capacity market.



Capacity Market

Called "Planning Resource Auction" in MISO

CONE=cost
of new entry

Objective

– Minimize

$$\underbrace{\sum_{i=1}^{m} OfferPrice_i \times MWCleared_i}_{\text{Existing Capacity Bidding In}} + \underbrace{\sum_{z=1}^{Z} (CONE_z \times SysNewCap_z + CONE_z \times ZoneNewCap_Z)}_{\text{New Capacity}}$$

Market wide and zonal constraints

$$ClearedCap_Z = \sum_{i \in \{\text{all resource in zone z}\}} \{MWCleared_i\}$$

How does MISO know what "SysRequiredCap" and "$RequiredCap_z$" should be?

- **Market wide requirement:**

  SysClearedCap+SysNewCap ≥ SysRequiredCap

SysClearedCap=Σ_z $ClearedCap_z$
SysNewCap=Σ_z $SysNewCap_z$

- **Zonal export/import limits: For each zone z**

  $RequiredCap_Z - ImportLim_Z \leq ClearedCap_z + SysNewCap_Z \leq RequiredCap_z + ExportLim_z$

- **Zonal local reliability requirement: For each zone z**

  $ClearedCap_z + ZoneNewCap_z \geq RequiredCap_Z - ImportLim_Z$

$ZoneNewCap_z$, is capacity specific to zone z, that is not subject to export.

An updated, more detailed formulation is provided in MISO's Business Practice Manual (BPM) 011. See www.misoenergy.org/legal/business-practice-manuals/.

Capacity Market

Called "Planning Resource Auction" in MISO

CONE=cost of new entry

Objective function:

$$\min \underbrace{\sum_{i=1}^{m} \text{OfferPrice}_i \times \text{MWCleared}_i}_{\text{EXISTING CAPACITY BIDDING IN}} + \underbrace{\sum_{z=1}^{Z} \left(CONE_z \times \underbrace{\text{SysNewCap}_z}_{\text{New in Zone z, to be exported}} + CONE_z \underbrace{\text{ZoneNewCap}_z}_{\text{New in Zone z but not to export}} \right)}_{\text{NEW CAPACITY}}$$

subject to market-wide and zonal constraints:

- **market-wide constraint:**

$$\underbrace{\text{SysClearedCap}}_{\text{Existing Total}} + \underbrace{\text{SysNewCap}}_{\text{New Total}} \geq \text{SysRequiredCap}$$

$$\text{SysClearedCap} = \sum_{z} \sum_{i \in z} \text{MWCleared}_i \qquad \text{SysNewCap} = \sum_{z} \text{SysNewCap}_z$$

How does MISO know what "SysRequiredCap" and "RequiredCap$_z$" should be?

- **zonal import/export limits; for each zone z:**

$$\text{RequiredCap}_z - \text{ImportLim}_z \leq \underbrace{\sum_{i \in z} \text{MWCleared}_i}_{\text{Existing in Zone z}} + \underbrace{\text{SysNewCap}_z}_{\text{New in Zone z, to be exported}} \leq \text{RequiredCap}_z + \text{ExportLim}_z$$

- **zonal local reliability requirement; for each zone z:**

$$\text{RequiredCap}_z - \text{ImportLim}_z \leq \underbrace{\sum_{i \in z} \text{MWCleared}_i}_{\text{Existing in Zone z}} + \underbrace{\text{ZoneNewCap}_z}_{\text{New in Zone z but not to export}}$$

An updated, more detailed formulation is provided in MISO's Business Practice Manual (BPM) 011. See www.misoenergy.org/legal/business-practice-manuals/.

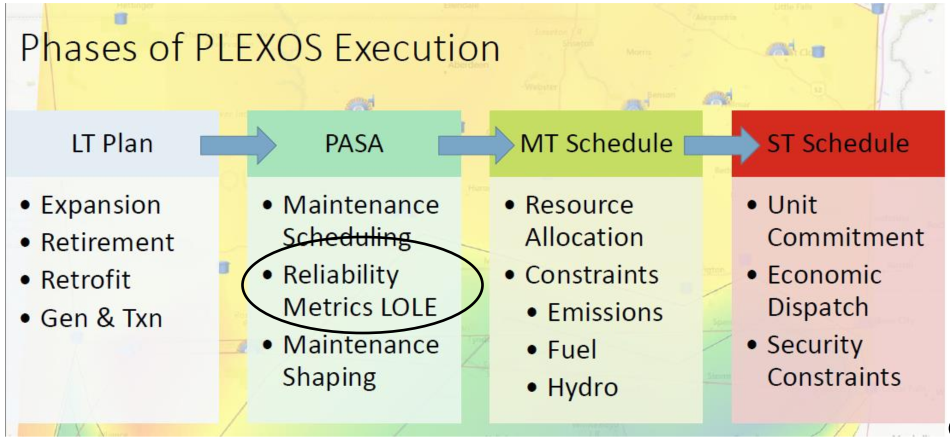
Capacity Market

Called "Planning Resource Auction" in MISO

How does MISO know what "SysRequiredCap" and "RequiredCap$_z$" should be?

Answer:

➔They evaluate reliability indices using resource adequacy software.



GE Energy

GE Multi-Area Reliability Simulation Software Program (MARS)

Accurate generation system reliability assessment for ensuring system adequacy to satisfy customer load demand

Is your generation system reliable?

In today's energy industry where participants and their roles are in a constant state of flux, having the ability to quickly and accurately assess the reliability of generation systems is more important than ever. The Multi-Area Reliability Simulation software program (MARS) enables quick and accurate assessment of the reliability of a generation system comprised of any number of interconnected areas. Accurate system assessment is crucial for ensuring the adequacy of the system in terms of satisfying future load demand.

MARS software puts your system's reliability to the test

MARS software is a system simulation program that models the generation system, the interconnections between areas, and the chronological hourly load demand. MARS software models the system in great detail with accurate recognition of random events such as equipment failures, as well as deterministic rules and policies that govern system operation. MARS software can model any number of areas and pools to study multi-area issues such as:

- generation system adequacy
- installed capacity requirements
- benefits of reserve sharing
- need for implementing emergency operating procedures
- reliability impact and capacity value of variable resources such as wind and solar.

A sequential Monte Carlo simulation forms the basis for MARS software. The Monte Carlo method provides a fast, versatile, and easily expandable program that can be used to fully model various generation and reserve sharing options.

MARS software has the capability to model the following different types of resources, such as thermal, energy-limited (hydro), and variable resources (wind, solar, etc.)

MARS software makes the following reliability indices available on both an isolated (zero ties between areas) and interconnected (using the input transfer limits between areas) basis:

- Daily LOLE (loss-of-load expectation) (days/year)
- Hourly LOLE (hours/year)
- LOEE (loss-of-energy expectation) (MWh/year)
- Frequency of outage (outages/year)
- Duration of outage (hours/outage)
- Need for initiating emergency operating procedures (days/year and hours/year)

LOLE (loss of load expectation) is the amount of time during a planning period the system can expect to interrupt load.

Industry norm:

$LOLE_{Required}$≤1 day in 10 years

So MISO identifies SysRequiredCap and RequiredCap$_z$ to satisfy this requirement.

See http://home.engineering.iastate.edu/~jdm/ee653/ee653schedule.htm for more info on reliability eval.

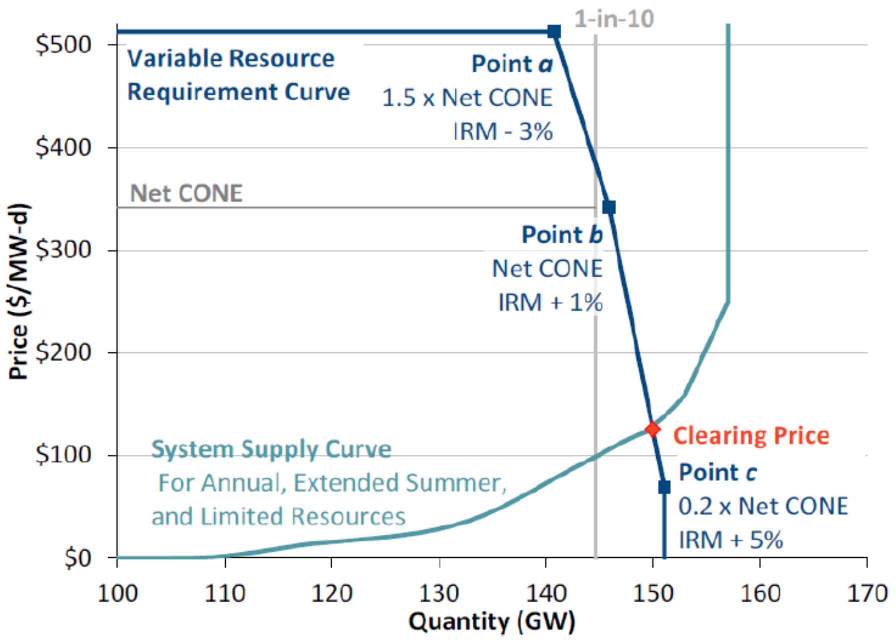
Capacity Market

Called "Planning Resource Auction" in MISO

Where do the revenues come from to fund a capacity market?

An auction is conducted for suppliers using a specified demand curve, illustrated below. The demand curve is determined administratively, based on the cost of new entry (CONE).

IRM: installed reserve margin.



T. Jenkin, P. Beiter, and R. Margolis, "Capacity payments in restructured markets under low and high penetration levels of renewable energy," NREL Technical Report NREL/TP-6A20-65491, Feb, 2016, available https://www.nrel.gov/docs/fy16osti/65491.pdf.

Capacity obligations are determined by a LSE's peak load contribution (PLC) during a certain timeframe. In MISO, an LSE PLC is determined by their usage during the peak hour from the previous year. The peak hour is the hour during which the usage was the highest across the ISO. The LSE is charged the market clearing price × PLC.

https://business.directenergy.com/understanding-energy/managing-energy-costs/deregulation-and-energy-pricing/capacity-markets

Three additional questions that capacity markets do not answer…

- How do vertically-integrated rate-regulated utilities, under traditional regulation, know what kind of technologies to build?
- How do market participants know what “Offer Price” to submit and how do they know what kind of generation to build?
- How can ISO’s forecast generation builds beyond what is in the interconnection queue?

➔Solutions to the Generation Expansion Planning (GEP) problem can contribute to answering these questions.