PNM 2020-2039 Integrated Resource Plan

AUGUST 20, 2019

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AGENDA

2020-2039 IRP PUBLIC ADVISORY MEETING #2: ETA & UTILITIES 101

- Welcome and Introductions
- Safety and Ground Rules
- ETA Roundtable
- Utilities 101
- Outline of next meeting's topic

Nick Phillips
Director, Integrated Resource Planning

Mr. Phillips manages the PNM Resource Planning department and is responsible for developing PNM resource plans and the regulatory filings to support those resource plans.

Prior to joining PNM, Mr. Phillips was involved with numerous regulated and competitive electric service issues including resource planning, transmission planning, production cost analysis, electric price forecasting, load forecasting, class cost of service analysis, and rate design.

Mr. Phillips received the Degree of Master of Engineering in Electrical Engineering with a concentration in Electric Power and Energy Systems from Iowa State University of Science and Technology, and the Degree of Master of Science in Computational Finance and Risk Management from the University of Washington Seattle.

SAFETY AND LOGISTICS

- In case of an emergency please exit to the LEFT of the stage.
- Another exit is through the main entry of the Museum.
- Restrooms are located behind the Admission desk around the corner down the hall to the left.

MEETING GROUND RULES

01

- Questions and comments are welcome – One Person Speaks at a Time

02

- Reminder; today's presentation is not PNM's plan or a financial forecast, it is an illustration of the IRP process

03

- We ask that you complete the Questions/Comments sign-up sheet in advance of requesting the microphone to pose your written question or comment. All questions will be logged
- Questions and comments should be respectful of all participants

04

- These meetings are about the 2020 IRP, questions and comments should relate to this IRP. Any questions or comments related to other regulator proceedings should be directed towards the specific filing

DISCLOSURE REGARDING FORWARD LOOKING STATEMENTS

The information provided in this presentation contains scenario planning assumptions to assist in the Integrated Resource Plan public process and should not be considered statements of the company's actual plans. Any assumptions and projections contained in the presentation are subject to a variety of risks, uncertainties and other factors, most of which are beyond the company's control, and many of which could have a significant impact on the company's ultimate conclusions and plans. For further discussion of these and other important factors, please refer to reports filed with the Securities and Exchange Commission. The reports are available online at www.pnmresources.com.

The information in this presentation is based on the best available information at the time of preparation. The company undertakes no obligation to update any forward-looking statement or statements to reflect events or circumstances that occur after the date on which such statement is made or to reflect the occurrence of unanticipated events, except to the extent the events or circumstances constitute material changes in the Integrated Resource Plan that are required to be reported to the New Mexico Public Regulation Commission (NMPRC) pursuant to Rule 17.7.4 New Mexico Administrative Code (NMAC).

ETA ROUNDTABLE

THE ENERGY TRANSITION ACT

KEY POINTS THAT AFFECT THE IRP

•Sections 2(H), 4(A) Energy Transition Costs (related to coal plants) are fully recoverable, including undepreciated investments, plant decommissioning and mine reclamation costs, and severance and job training costs.

•Section 10 After issuance of Energy Transition Bonds, PNM's owned generation and PPAs with terms of 24-months or longer dedicated to serving retail customers shall not emit, on average, more than 400 pounds of CO_2 by January 1, 2023 and not more than 200 pounds by January 1, 2032. The Commission shall adopt rules to implement this section.

Year	Old RPS % of Retail Sales (%)[1]	New RPS % of Retail Sales (%)[2]	New CO2 Emission Rate Target (lbs/MWh)[3]
2015	15%	15%	n/a
2020	20%	20%	n/a
2025	20%	40%	400
2030	20%	50%	400
2035	20%	50%	200
2040	20%	80%	200*
2045	20%	80%	0

Notes

1 *3% RCT, included adjustments for exempt and large customers*

2 *$60/MWh RCT, removes adjustments for exempt and large customers*

3 *Three-year compliance period, 400 lbs/MWh beginning 1/1/2023, 200 lbs/MWh beginning 1/1/2032*

* *PNM has stated its goal is 0 by 2040*

THE ENERGY TRANSITION ACT

KEY POINTS THAT AFFECT THE IRP

Year	Retail Sales (GWh)	SJ Continues CO2 Rate (lbs/MWh)	Scenario 1 CO2 Rate (lbs/MWh)	Scenario 2 CO2 Rate (lbs/MWh)	Scenario 3 CO2 Rate (lbs/MWh)
2019	9,042	901	892	892	892
2020	9,539	895	905	905	905
2021	9,834	722	743	743	744
2022	10,055	740	536	590	494
2023	10,051	728	397	467	365
2024	10,051	685	354	417	327
2025	10,070	713	368	384	347
2026	10,115	707	382	391	373
2027	10,189	656	338	336	322
2028	10,219	653	340	334	345
2029	10,249	645	337	335	359
2030	10,280	587	307	308	314
2031	10,310	604	311	306	306
2032	10,341	502	178	178	172
2033	10,372	439	127	139	114
2034	10,410	470	105	125	103
2035	10,456	498	136	143	139
2036	10,498	441	100	105	100
2037	10,546	468	96	107	103
2038	10,593	514	86	96	106

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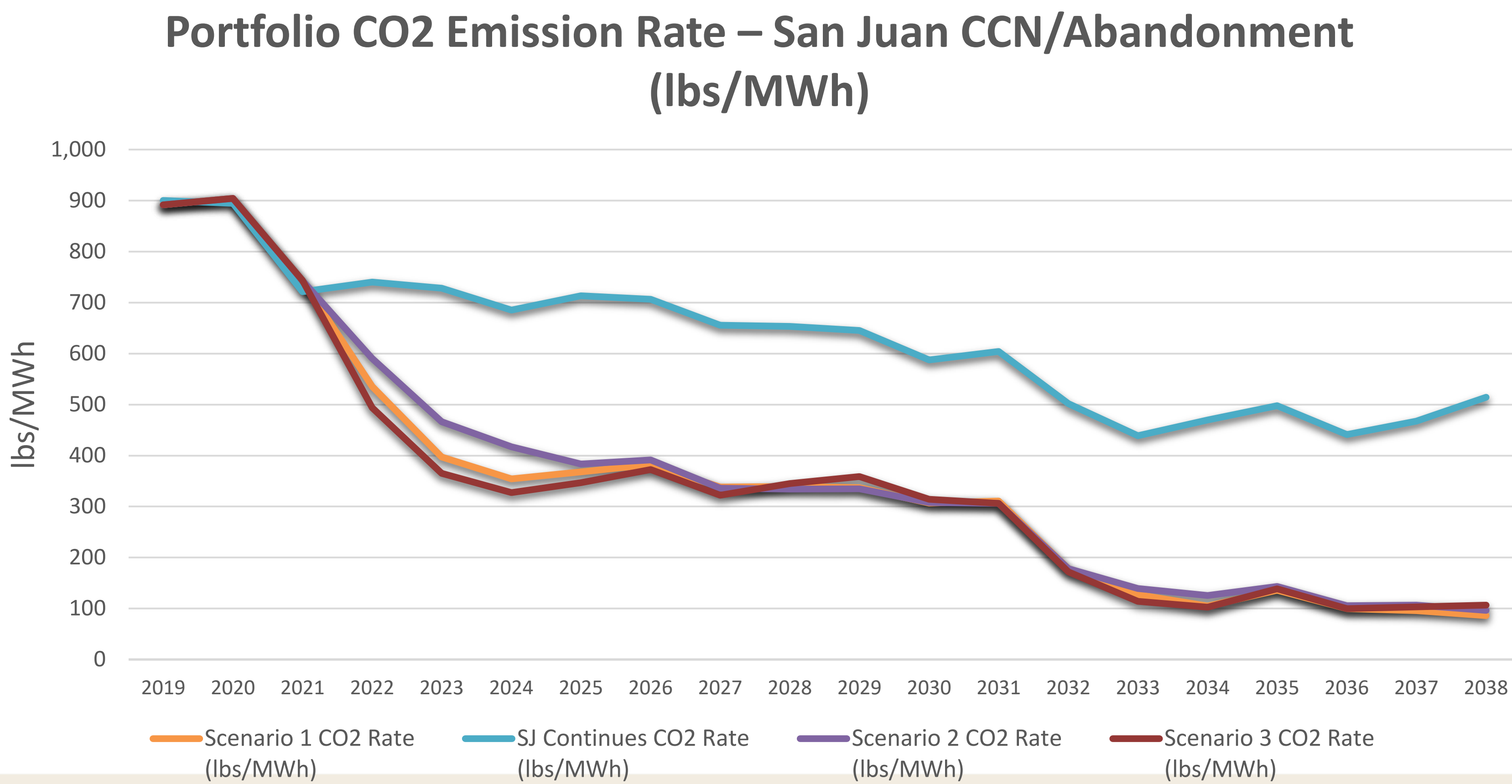
THE ENERGY TRANSITION ACT

KEY POINTS THAT AFFECT THE IRP



THE ENERGY TRANSITION ACT

KEY POINTS THAT AFFECT THE IRP

Section 29 The RPS increases to 40% in 2025, 50% in 2030, 80% in 2040 (provided that compliance "shall not require the public utility to displace zero carbon resources in the utility's generation portfolio"), and zero carbon resources shall supply 100% by 2045.

– CO_2 emitting resources may not be reassigned, redesignated or sold as a means of complying with the RPS.

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THE ENERGY TRANSITION ACT

KEY POINTS THAT AFFECT THE IRP

- Meeting the RPS shall not result in material increases to greenhouse gas emissions from entities not subject to commission oversight and regulation.
- By eliminating the large customer cap and exempt customer exemptions, the RPS results in higher amounts of renewable energy under the ETA than it would have been under the previous version of the law at the same RPS percentage.
- PNM may not use unbundled RECs to comply with the RPS; the associated energy must be delivered to PNM's system.

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THE ENERGY TRANSITION ACT

KEY POINTS THAT AFFECT THE IRP

- Section 30 Contracts to purchase renewable energy must include conveyances to PNM of all associated RECs.

- Section 31 A generating station that PNM has received a CCN for may be retired, with PNM recovering undepreciated investments, if the replacement has less or zero CO2 emissions.

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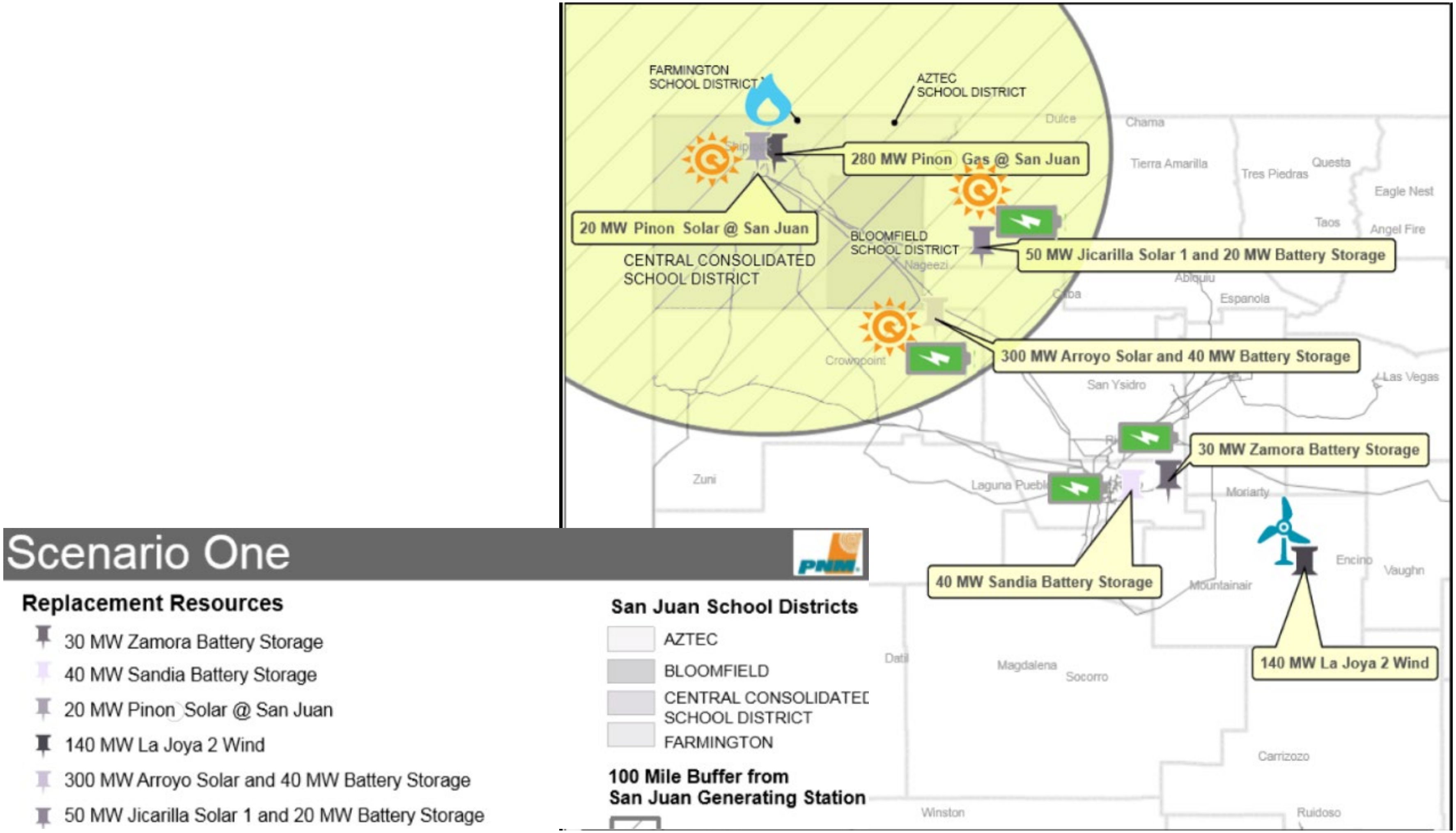
ETA ROUNDTABLE - OVERVIEW

	Proposed Scenario	Alternative Scenarios		
	Hybrid	San Juan Location	No Fossil Fuels	All Renewables
PNM Owned Resources	• 280 MW gas(1) • 70 MW battery	• 476 MW gas(1)	• 40 MW battery(1) • 110 MW battery	-
Third Party Resources	• 350 MW solar • 60 MW battery		• 500 MW solar • 260 MW battery	• 1,059 MW wind • 975 MW solar
Balancing Cost / Environment / Reliability:				
Incremental cost	$4,678M	$4,732M (+$54M)	$4,834M (+$156M)	$5,452M (+$774M)
CO_2 emission reduction(2)	62%	59%	65%	67%
Reliability	Managed risk, storage capacity ≤5% of energy usage, each battery location limited to 40 MW	Managed risk, storage capacity ≤5% of energy usage, each battery location limited to 40 MW	Increased risk as higher % of system based on unproven battery technology	Heightened reliability risks - does not meet federal reliability standards
Other	Partial San Juan property tax base	Maximizes San Juan property tax base	Limited San Juan property tax base	No San Juan property tax base

(1) Designates resources located in San Juan area school district
(2) From 2005 levels
Note: A PPA for 140 MW of wind energy was requested in a June 3, 2019 RPS Filing and included into all scenarios evaluated

ETA ROUNDTABLE - OVERVIEW



UTILITIES 101

AGENDA

- Why are we regulated
- Electric System Functions
- Energy vs Demand
- Load characteristics
- Rate Making
- Sample Bills

UTILITIES 101

REGULATION

- The United States has roots firmly planted in capitalism and the free market system, so why are public utilities regulated?
- High fixed cost vs low variable cost (high barrier to enter market)
  - Generation & transmission assets required to generate, transmit and distribute power require significant up-front capital & have long lead times to construct
  - Economies of scale
  - Once built, the operating costs are fairly low
  - Efficiency could be realized by building large plants and keeping them running as much as possible
  - This paradigm could lead to short-term competition and low prices and long-term monopolistic price gouging
  - It could also lead to duplication of facilities

UTILITIES 101

REGULATION

Electricity is a unique energy commodity

Electricity requires a production/conversion process

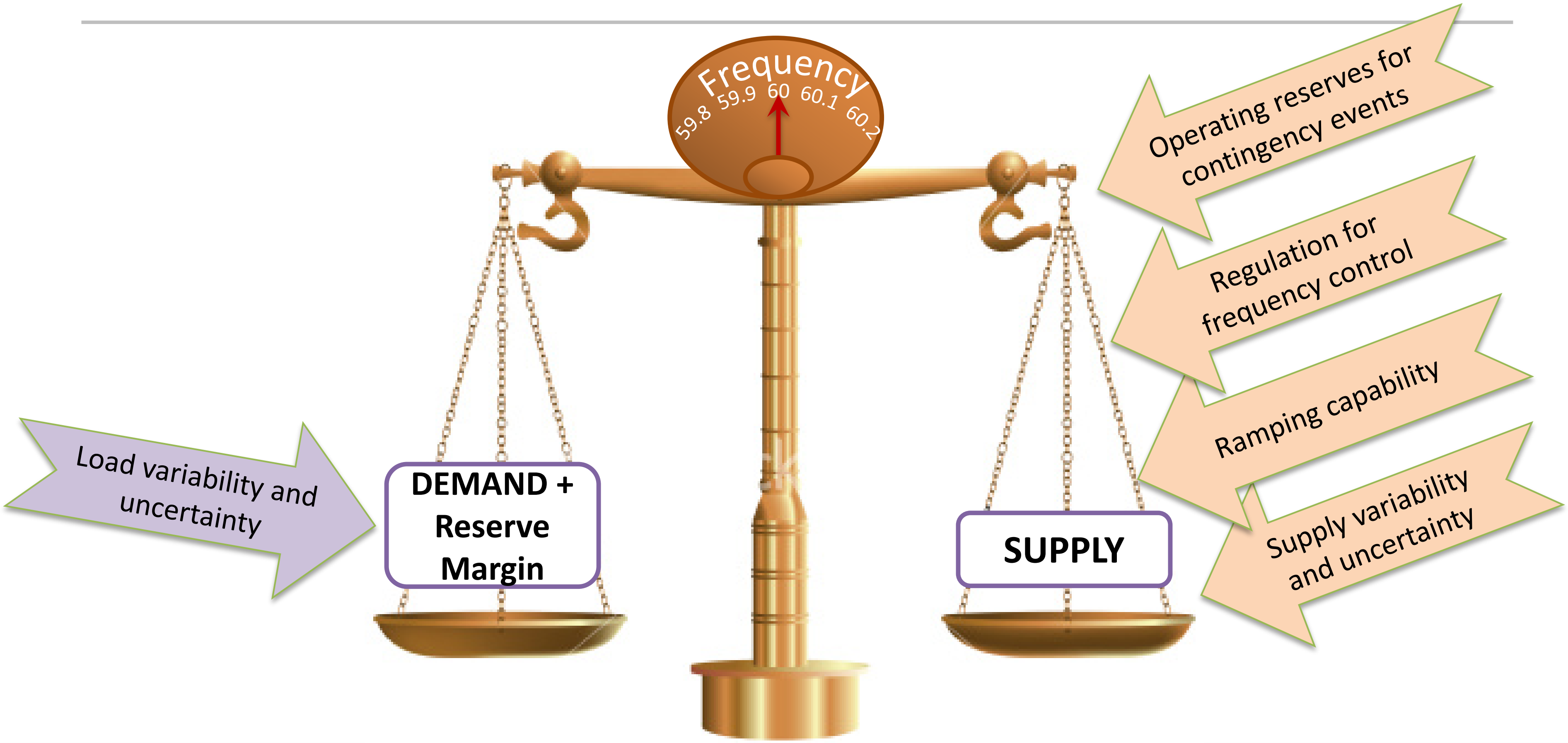
- Conversion of coal, gas, uranium, water, wind sunlight into electricity
- On the other hand, gas & water can be delivered directly to homes and businesses

Electricity must be generated at the time it is used

- We cannot effectively hold electricity in its raw state; we must convert it to a storage medium and re-generate, if we want to use later
- Must balance the system at all times

UTILITIES 101

REGULATION – BALANCING LOAD AND GENERATION



UTILITIES 101

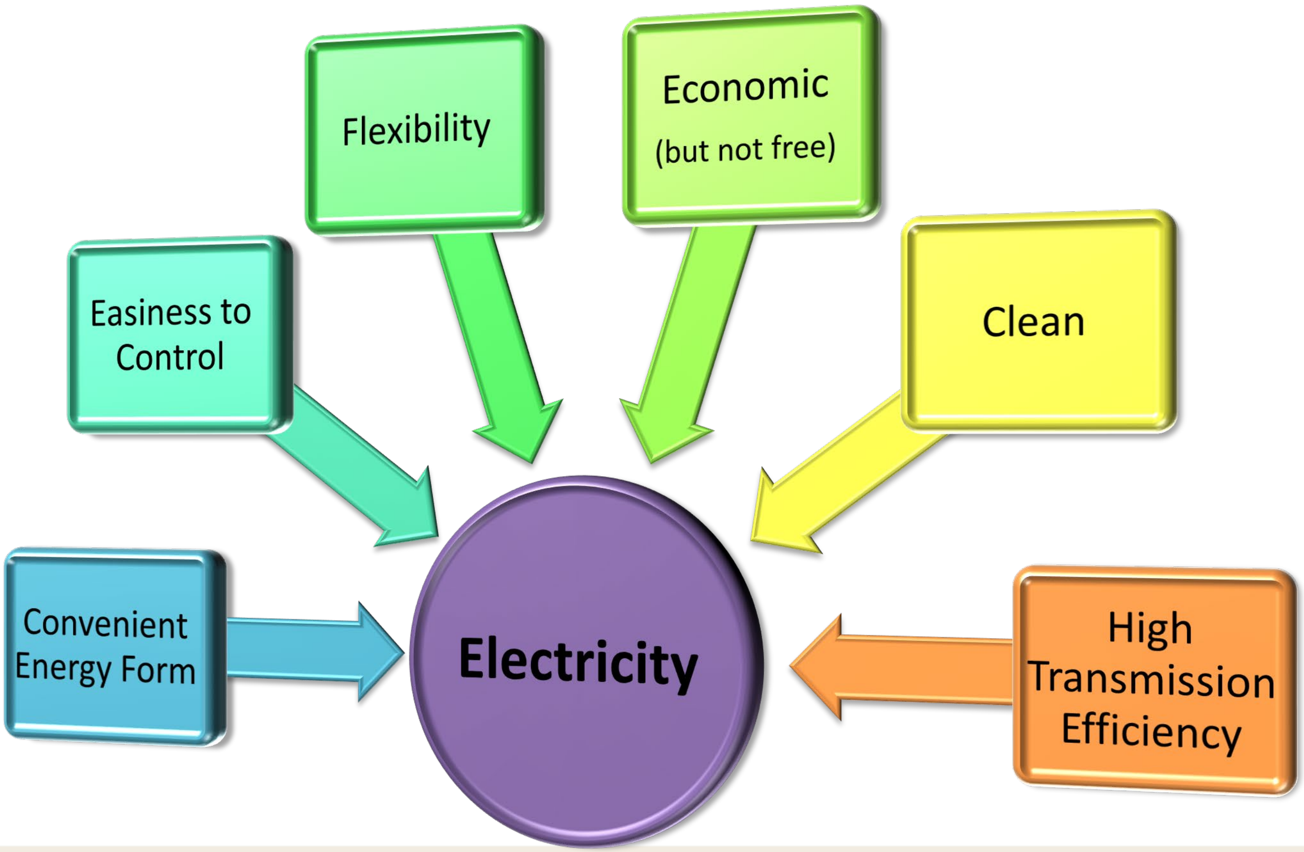
REGULATION – REGULATORY COMPACT

Effectively, regulation constitutes an agreement between a utility and the government: the utility accepts an obligation to serve in return for the government's promise to approve and allow rates that will compensate the utility fully for the costs it incurs to meet that obligation, including a fair opportunity to earn an authorized rate of return on investments.

As utilities make investments on behalf of customers, customers pay the utility that cost of that investment plus a reasonable rate of return. That is all to which the utility is entitled. The asset itself becomes dedicated to customers for its useful life. In many respects, utility customers are buying the actual system from the utility and, as customers pay off the rate base (mortgage) on each asset, that asset belongs to customer and is dedicated to customers.

UTILITIES 101

ELECTRICITY IS ESSENTIAL



ELECTRIC SYSTEM FUNCTIONS

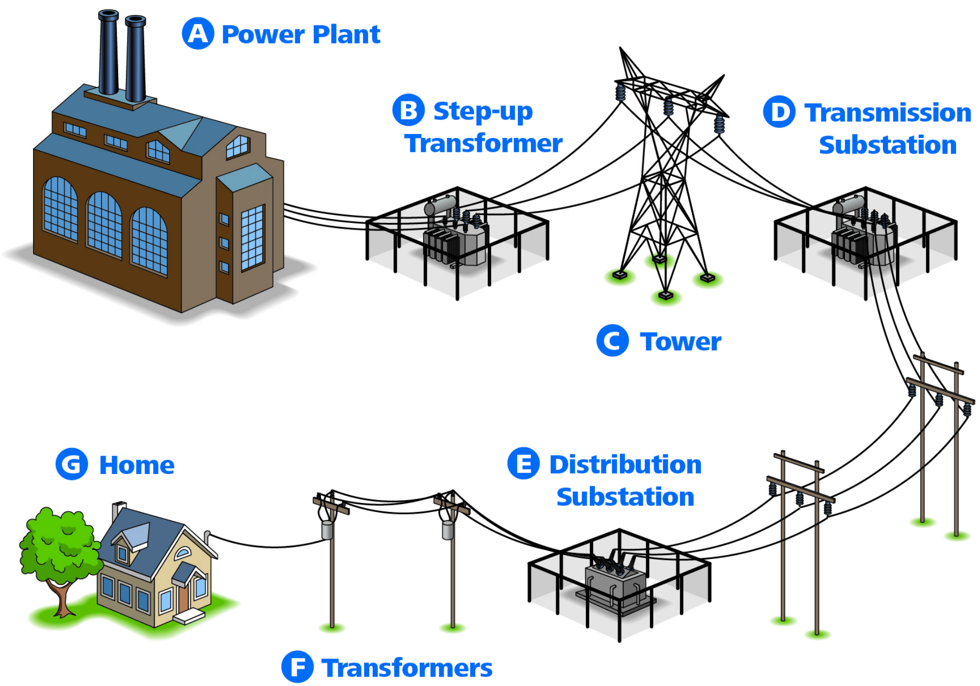
UTILITIES 101

ELECTRIC SYSTEM FUNCTIONS

- Generation
- Transmission
- Distribution
- Customer

UTILITIES 101

ELECTRIC SYSTEM FUNCTIONS



Source: Delmarva.com

LOAD CHARACTERISTICS

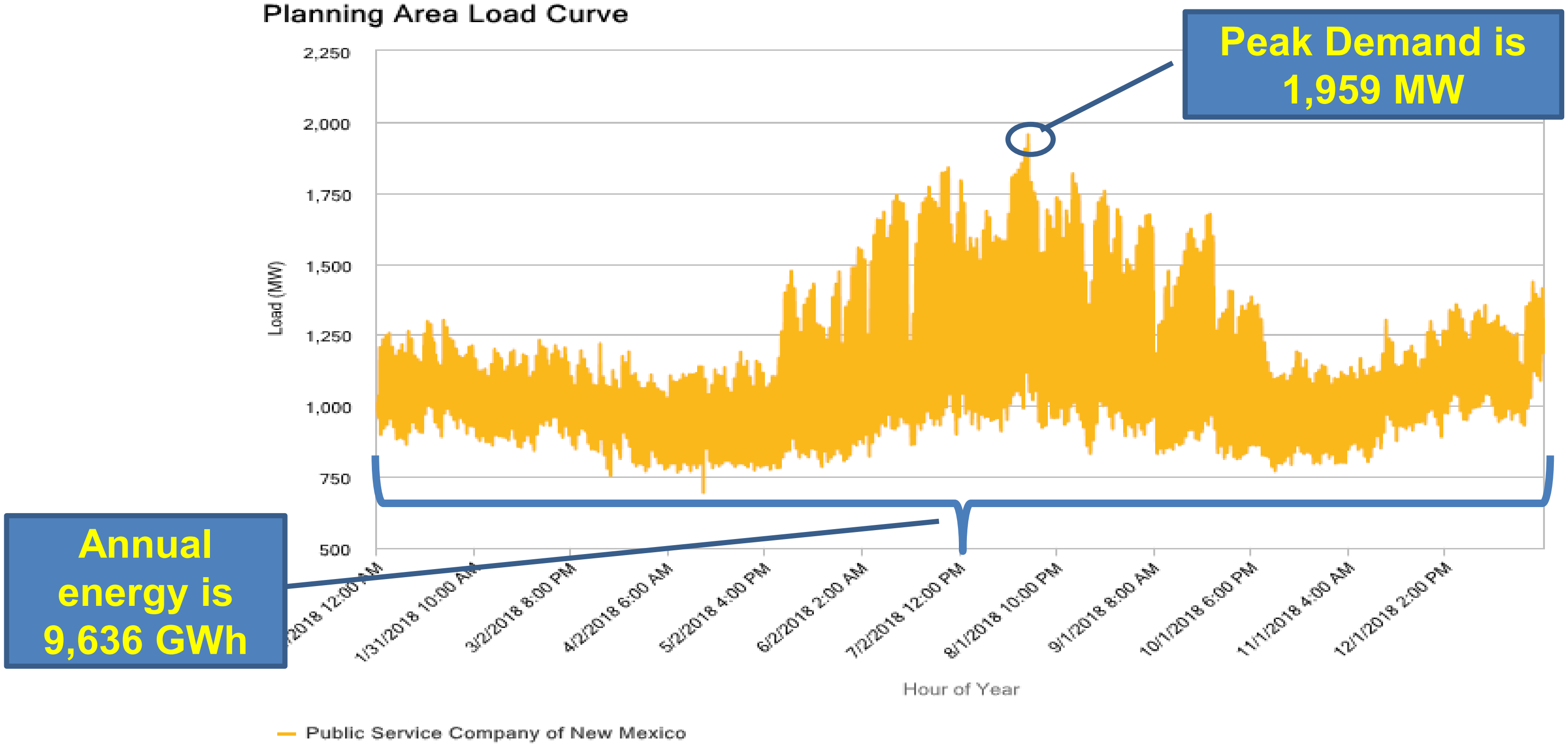
UTILITIES 101

GENERATION CONSIDERATIONS

- The utility must have adequate resources to meet the power demands of its customers
  - Adequate defined by regulators based on probabilistic loads and probabilistic supply
  - In times of stress, we can call on support from the regional grid, but we must also be prepared to support our neighbors
- We must meet the peak load and have a plan to meet future peak with resource additions
- “Load” is sometimes used interchangeably with demand, which is a customer’s electric requirements both instantaneously and over time

UTILITIES 101

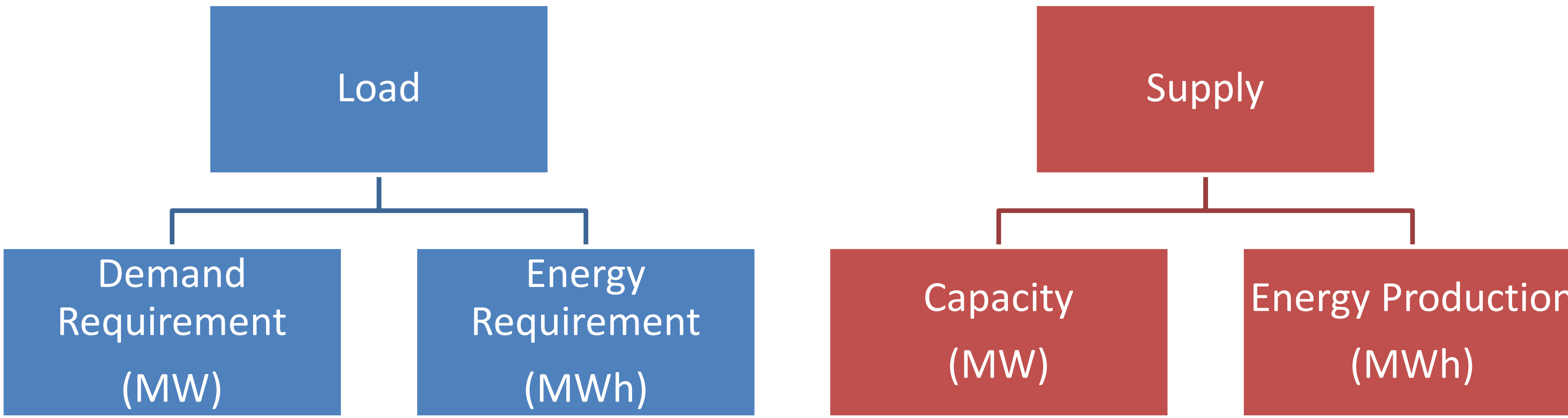
PEAK LOAD



GENERATION SUPPLY

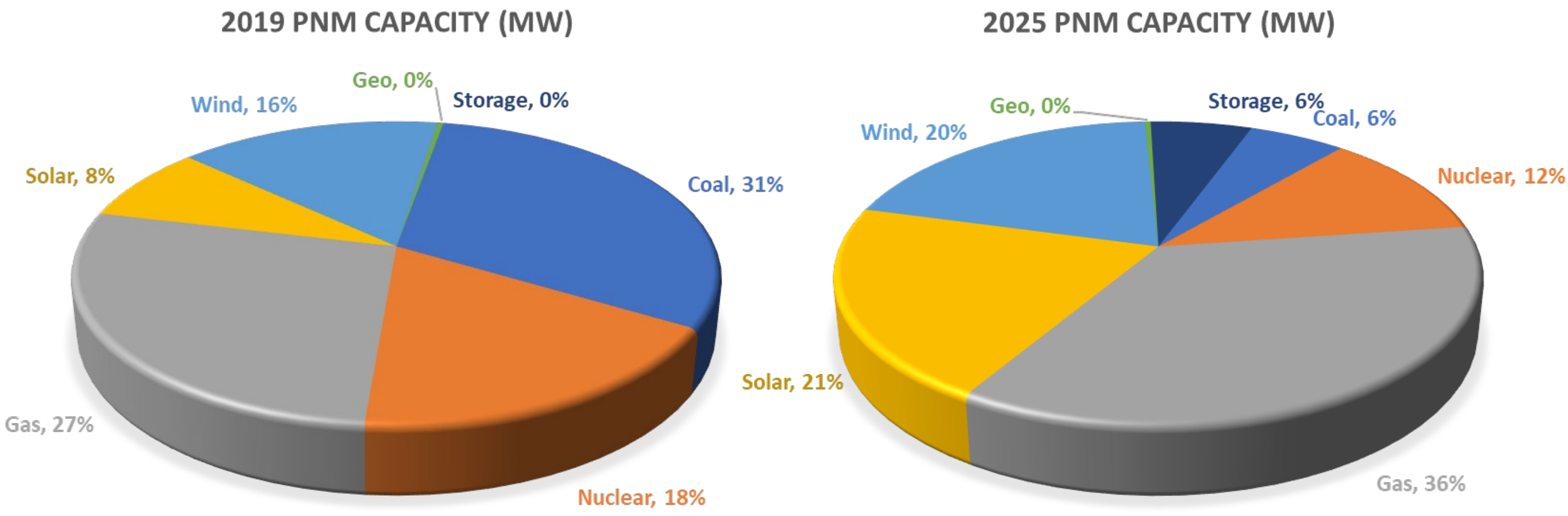
UTILITIES 101

SUPPLY AND DEMAND



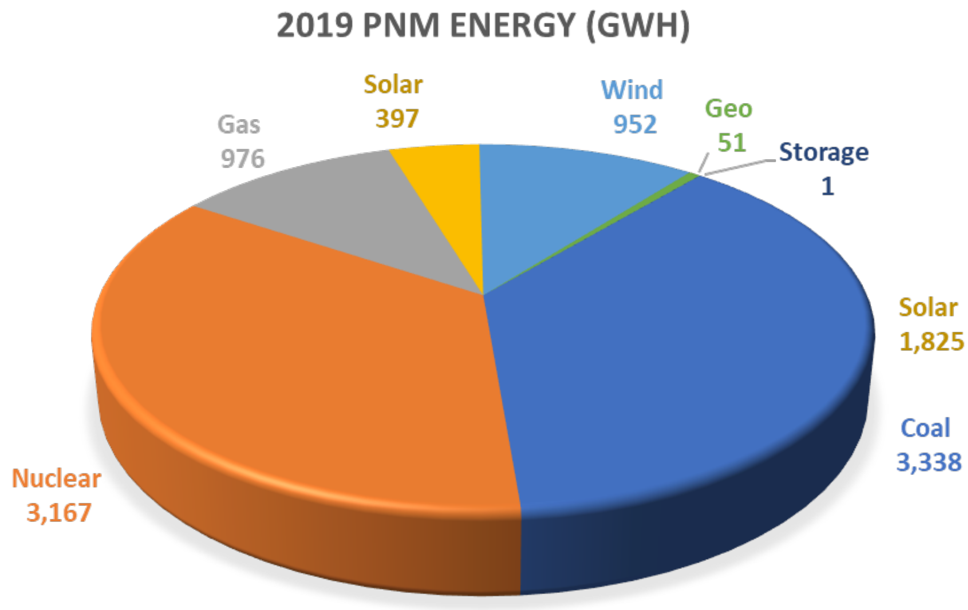
UTILITIES 101

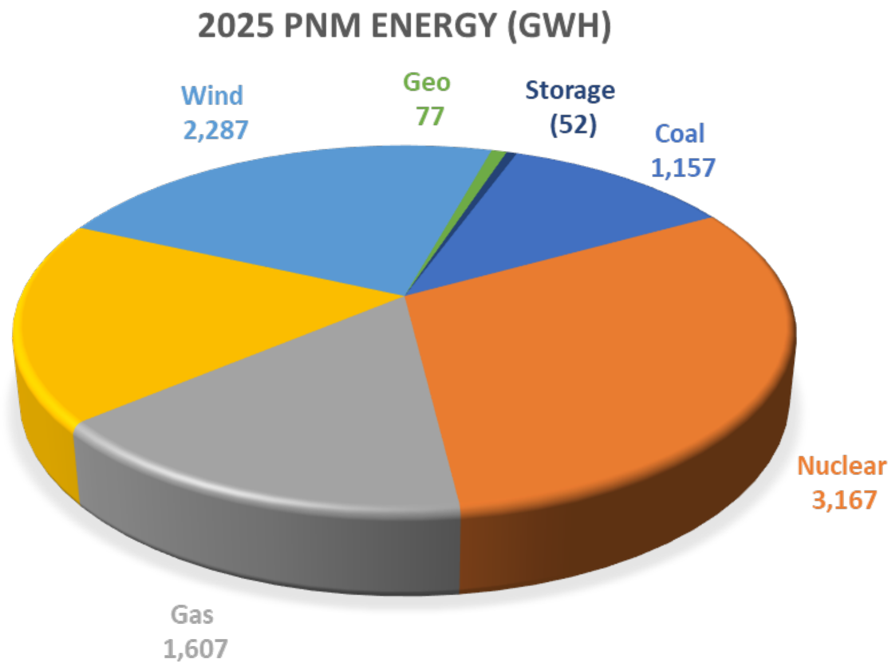
GENERATION - PNM GENERATION RESOURCE MIX -- CAPACITY



UTILITIES 101

GENERATION - PNM GENERATION RESOURCE MIX -- ENERGY





UTILITIES 101

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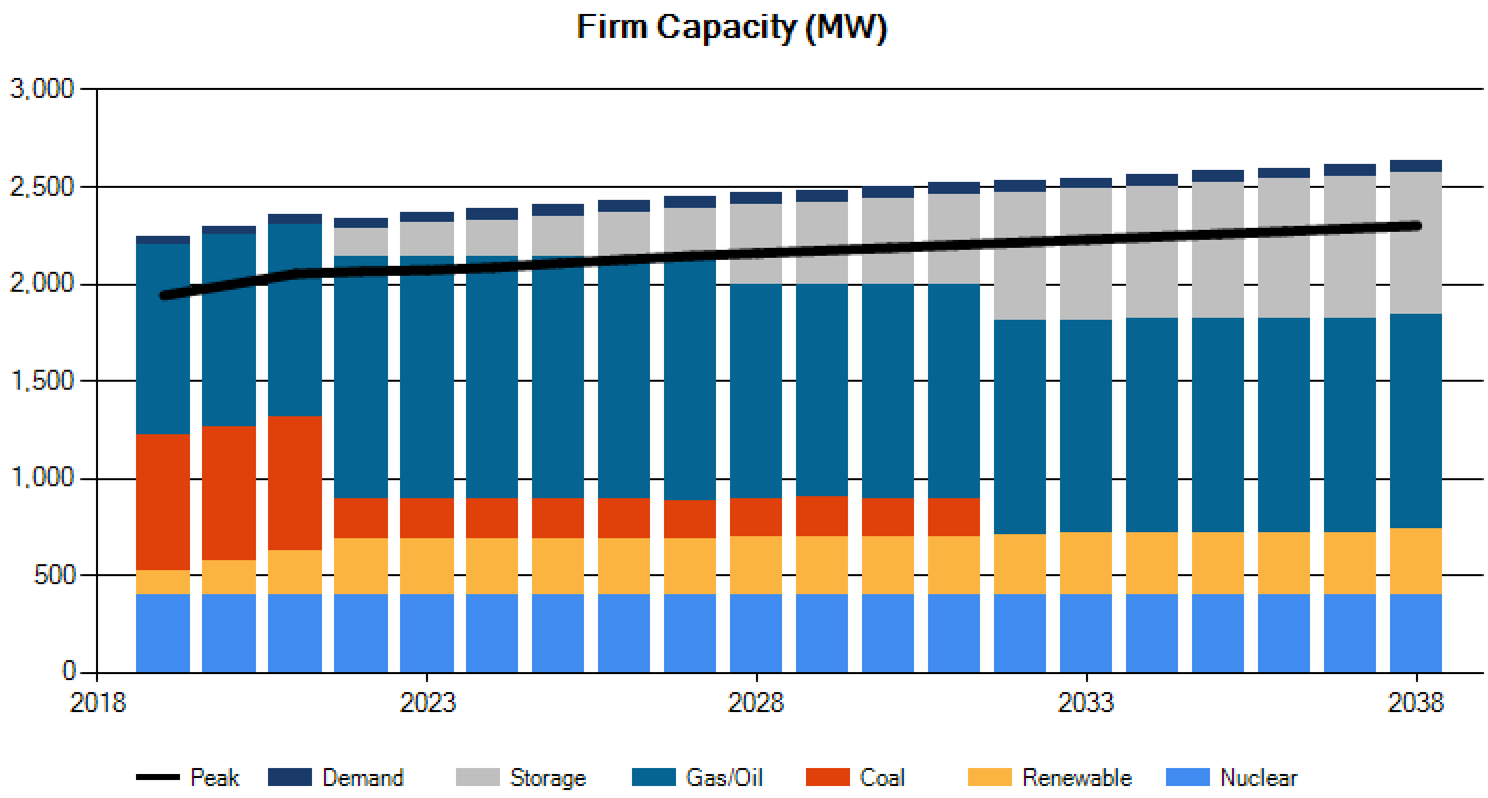

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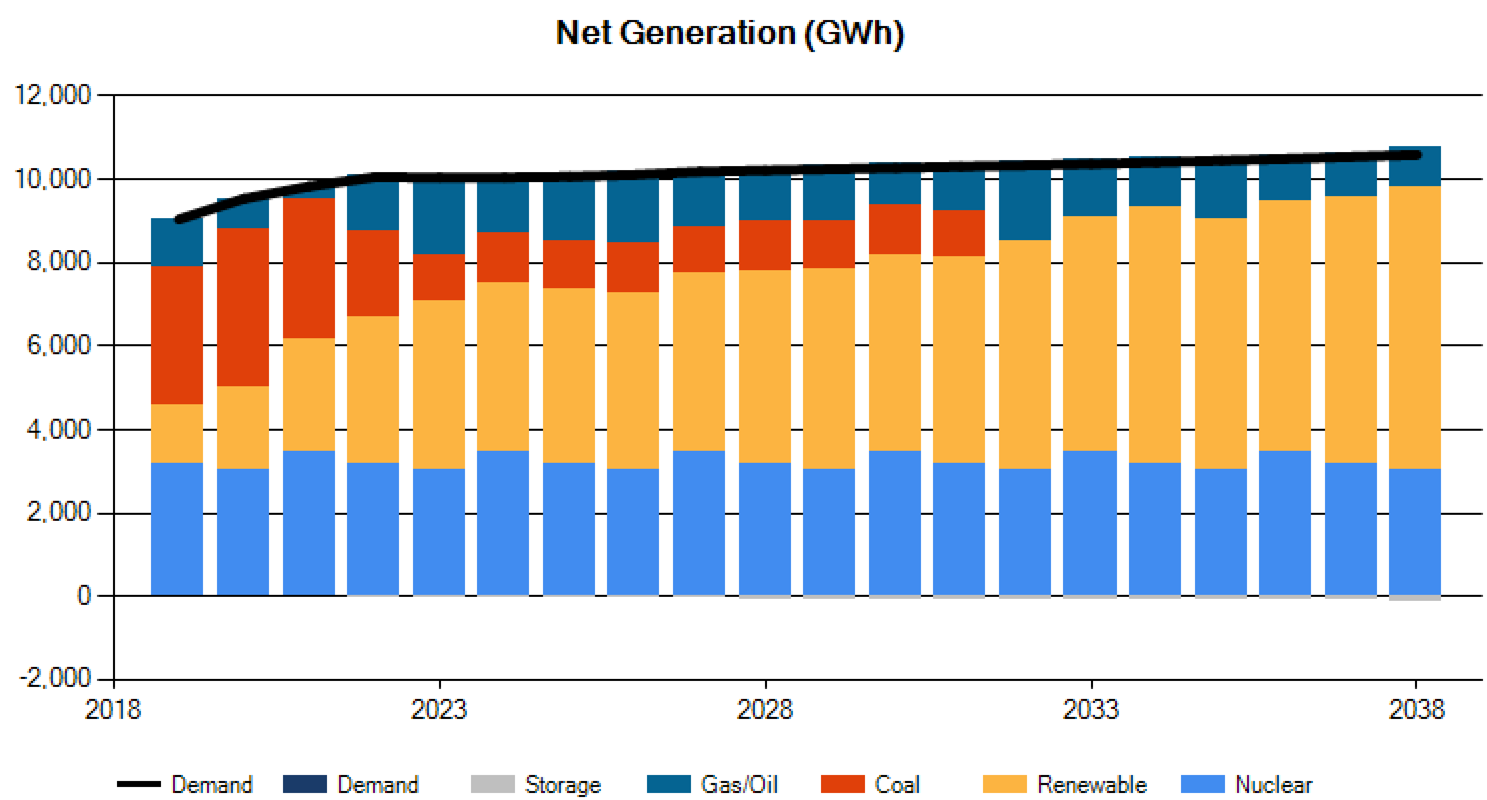
UTILITIES 101

GENERATION - PNM GENERATION RESOURCE MIX -- ENERGY



UTILITIES 101

GENERATION - INTERMITTENT VS DISPATCHABLE RESOURCES

Intermittent Resources

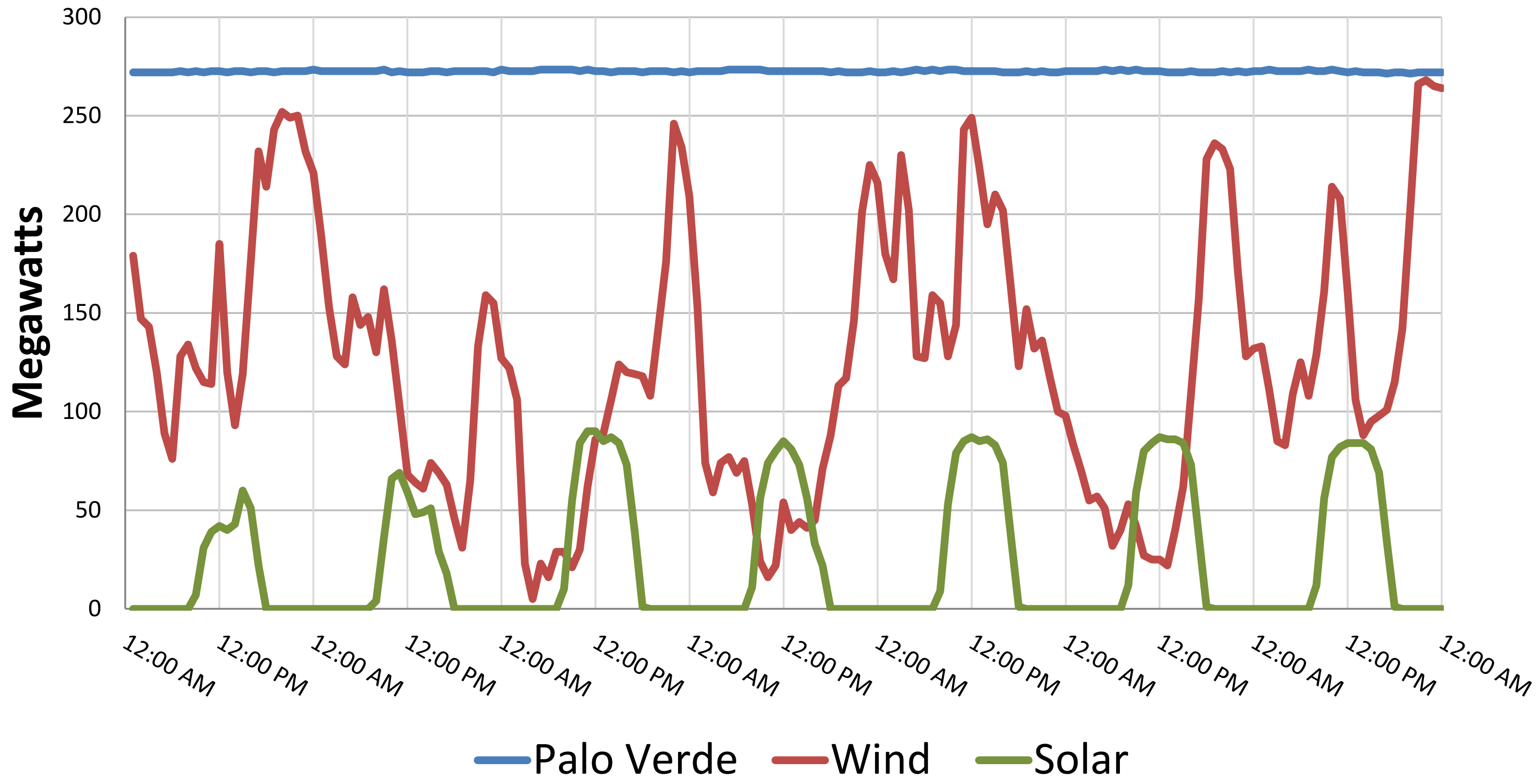
- Solar, Wind
- “must-take” resource
- Curtailable
- Dependent upon weather
- Energy production volatility
- No Fuel or emissions

Dispatchable Resources

- Coal, Nuclear, Gas/Oil, Storage
- Called upon to meet load and ancillary needs
- Fuel needed for fossil resources
- Emissions for fossil resources
- Not dependent on weather

UTILITIES 101

GENERATION - INTERMITTENT VS DISPATCHABLE RESOURCES



UTILITIES 101

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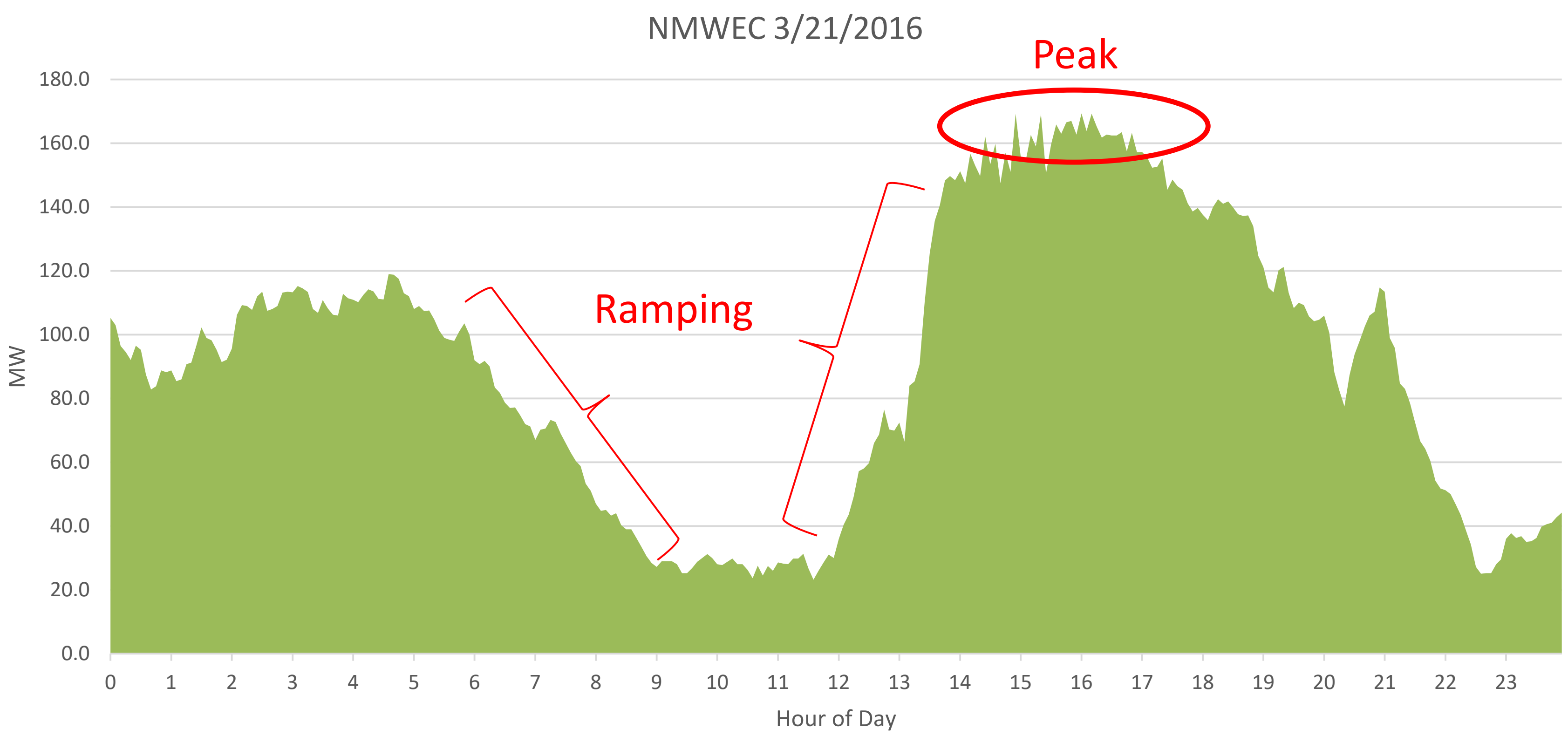
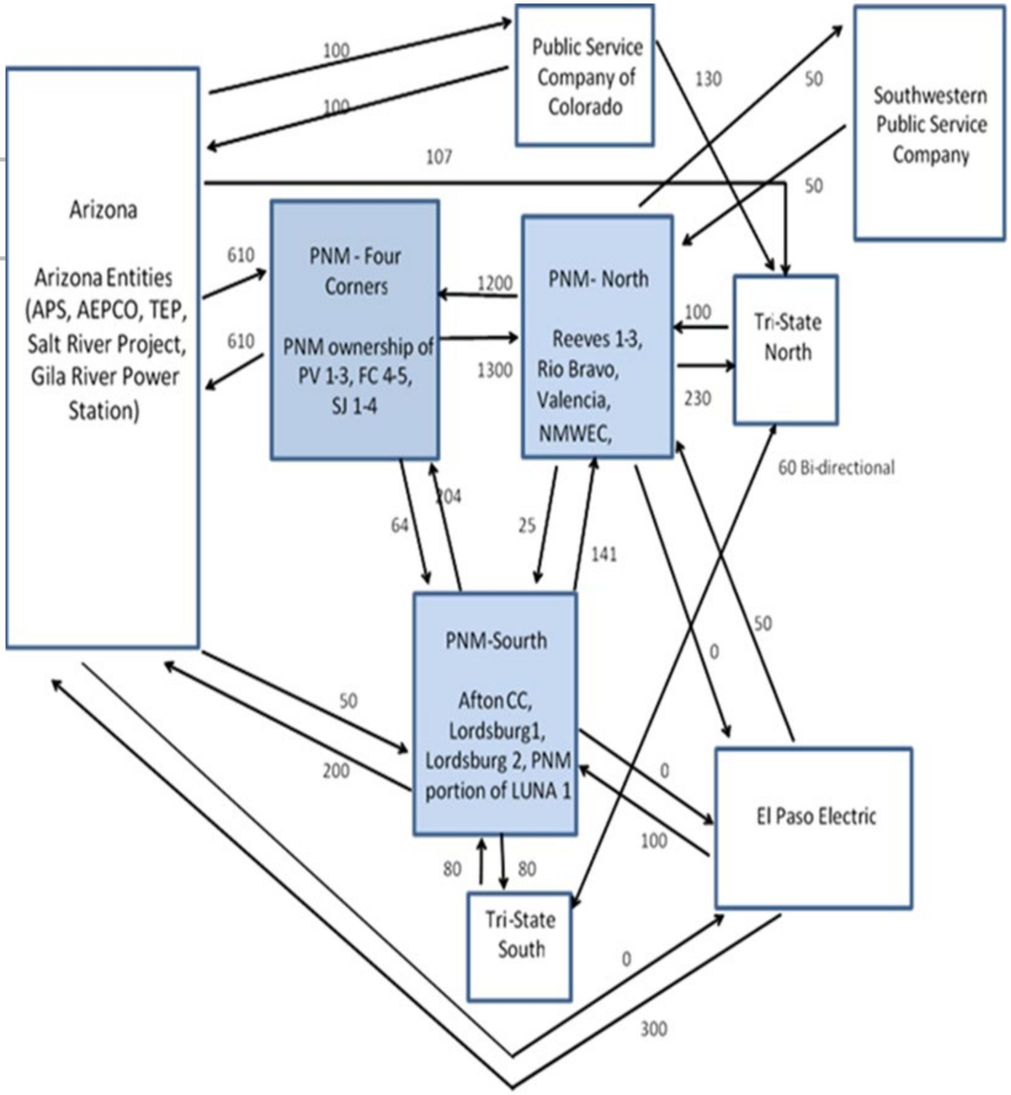


UTILITIES 101

TRANSMISSION

- PNM serves approximately 500,000 customers throughout New Mexico
- 15,000 miles of transmission and distribution lines
- PNM transmission system serves retail and wholesale customers per its Open Access Transmission Tariff
- Between 40-45% of transmission service is currently utilized by other entities
- Over 90% of load is located in north service territory
- **Transmission service to PNM north load center is fully committed**



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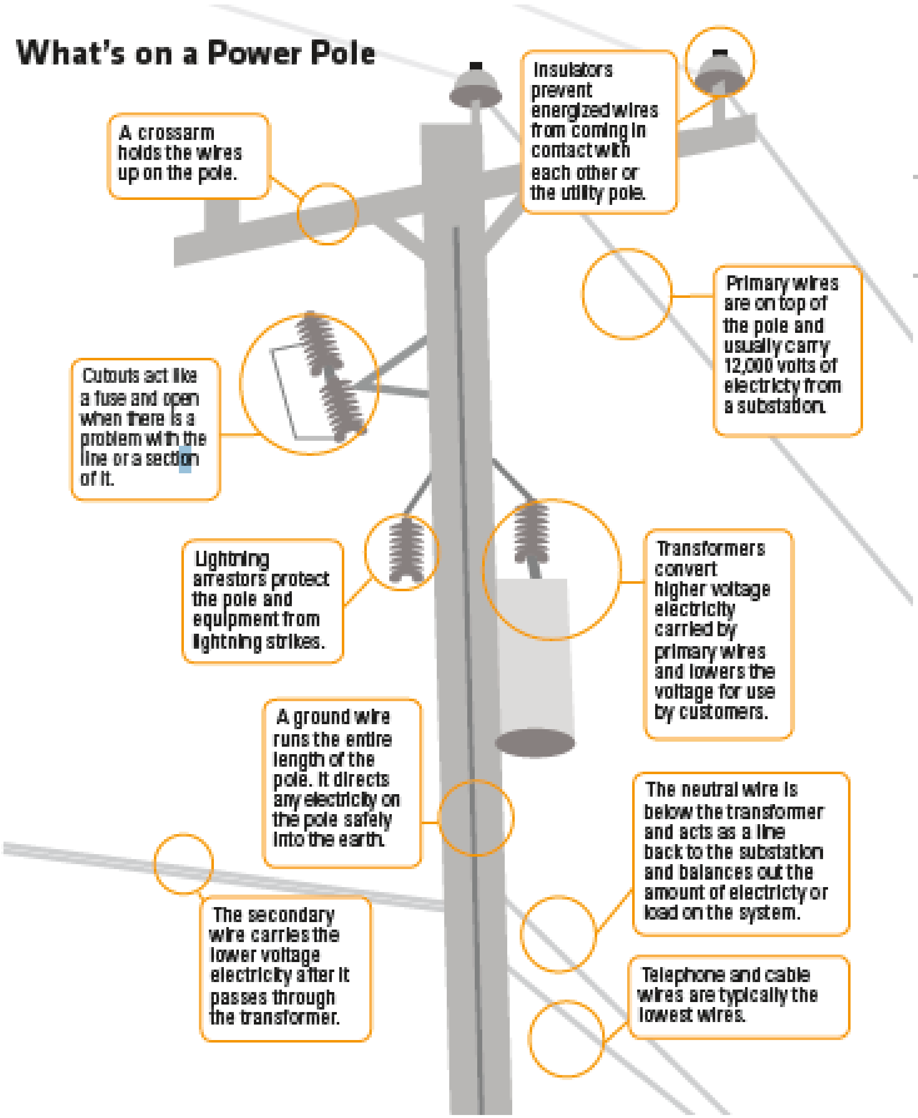
UTILITIES 101

DISTRIBUTION

PNM's distribution lines run 11,149 miles underground or on smaller towers that carry lower voltage electricity to homes and businesses.

The installation and upkeep of these power lines are critical to providing reliable electricity to customers.



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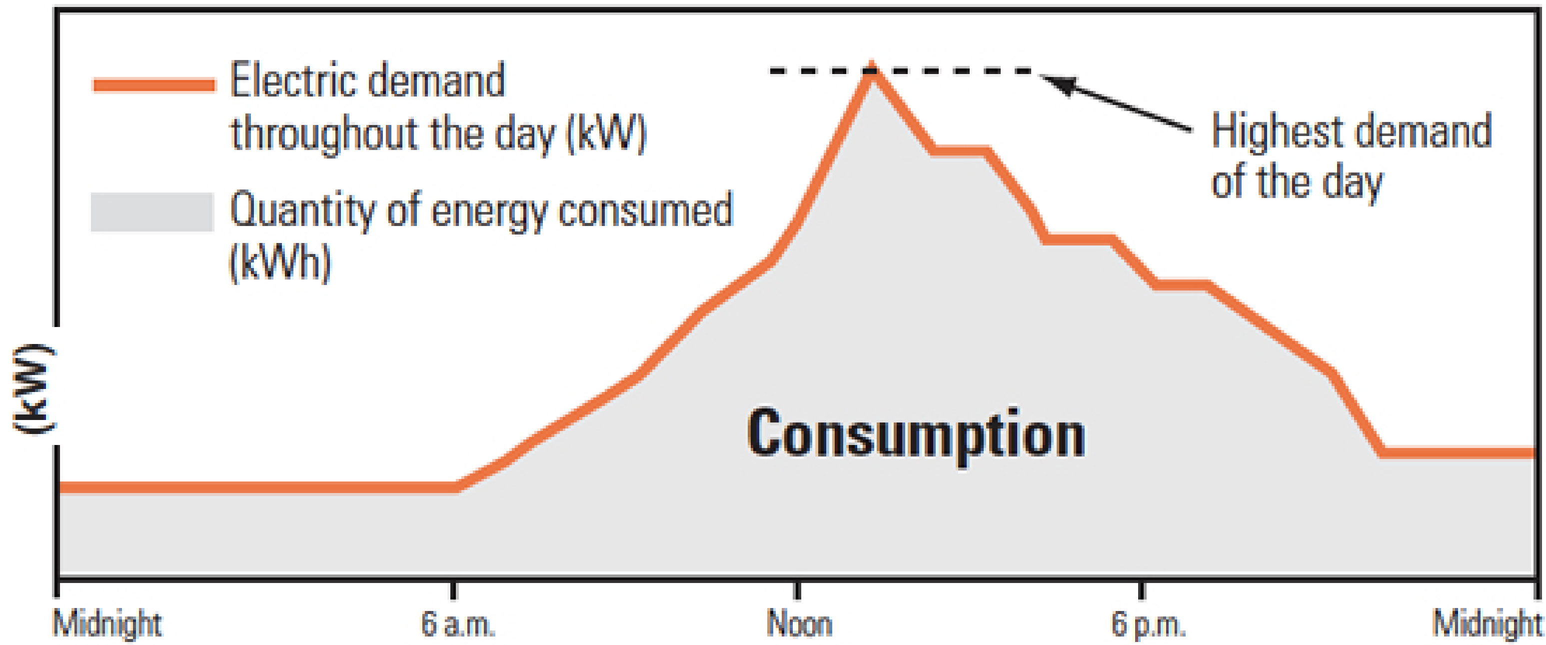
ENERGY VS. DEMAND

UTILITIES 101

ENERGY VS DEMAND



UTILITIES 101

ENERGY VS DEMAND

Electric Demand is the maximum amount of electricity that is being consumed at a given time. (Rate of work, analogous to speed)

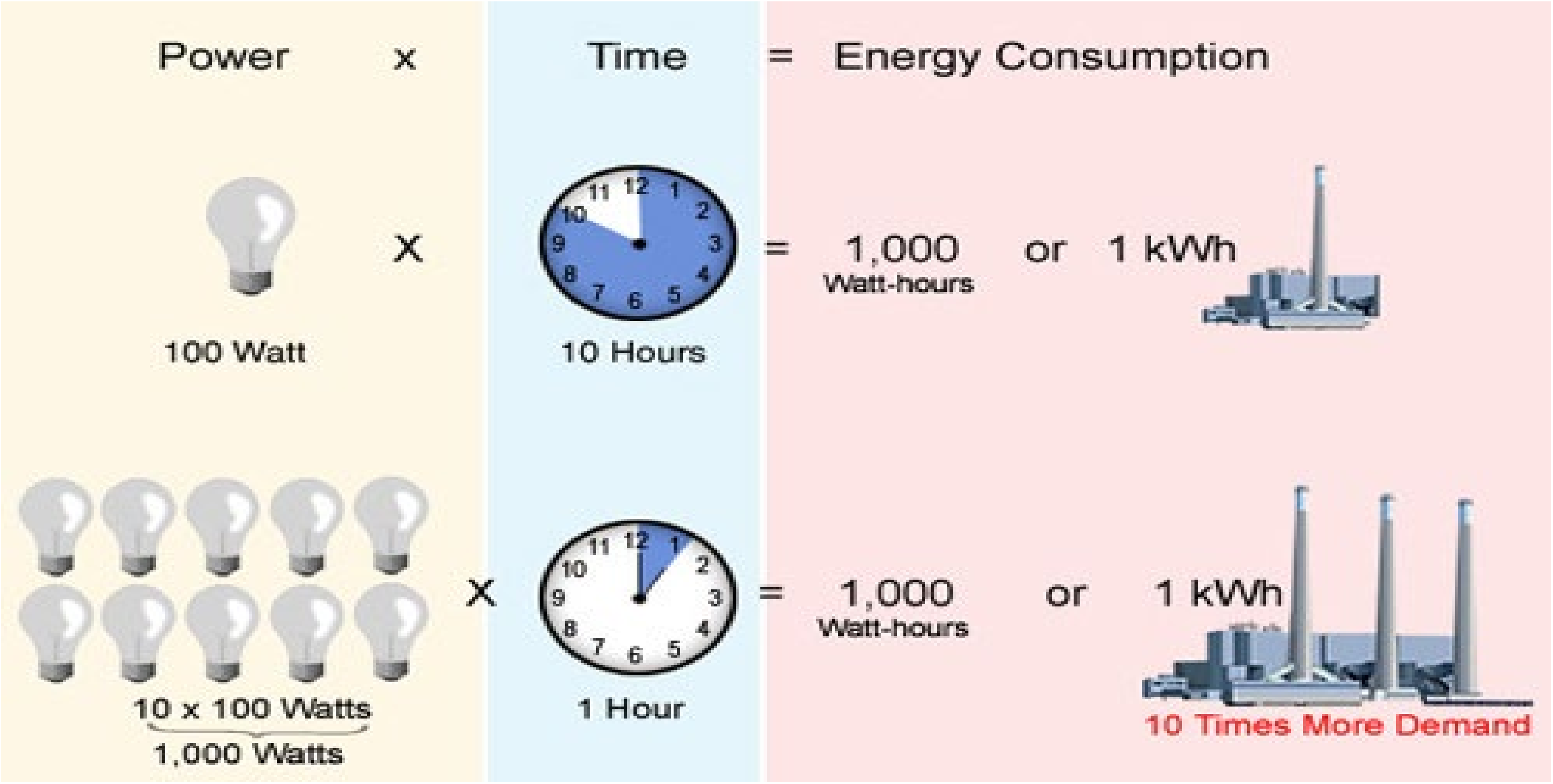
- It is measured in kilowatts (kW) and kilovolt ampere (kVA)

Energy Consumption is the total electricity used for a period of time. (Work, analogous to distance)

- It is measured in kilowatts hour (kWh)
- Energy = Demand summed (integrated) over time

UTILITIES 101

ENERGY VS DEMAND



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UTILITIES 101

LOADS

Electricity has unique and complicated customer usage patterns

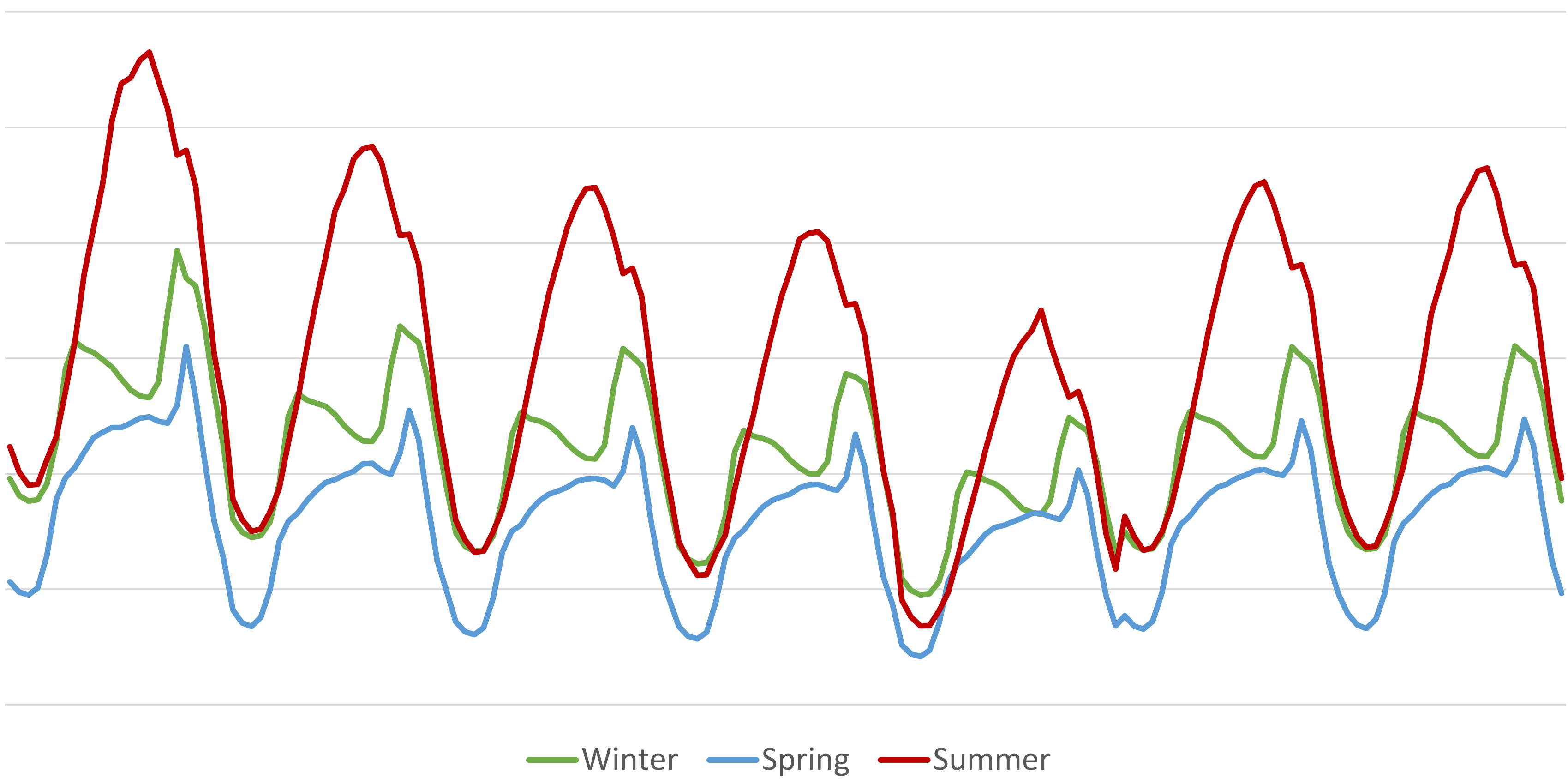
- Demands are naturally higher during the day than at night
- Demand is higher during hot summers/cold winters relative to mild spring and fall seasons

In order to reliably serve customers, this causes construction of generating capacity that may sit idle for most hours of the year

We must be able to follow the swings in load; not falling short or oversupplying

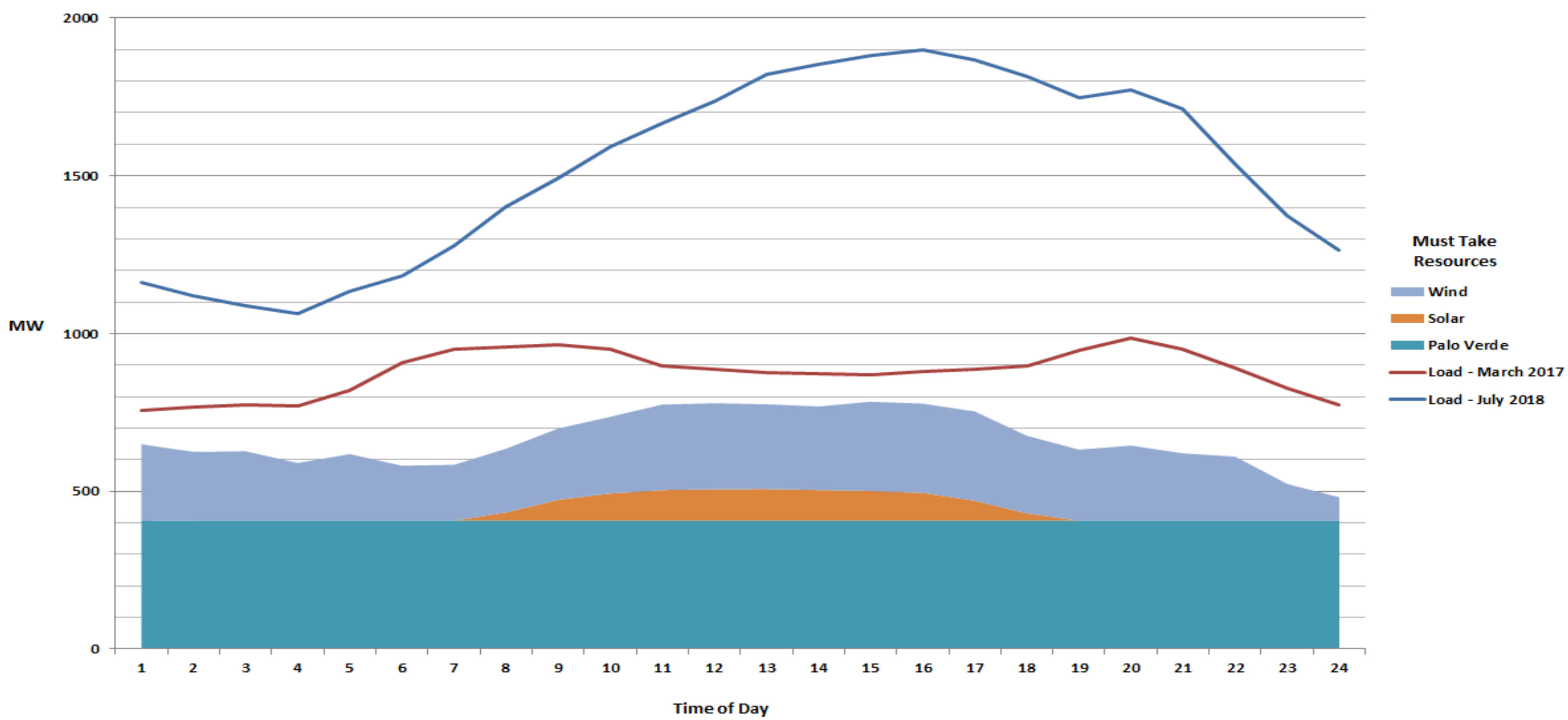
UTILITIES 101

LOADS – TYPICAL WEEKLY LOAD PROFILE



UTILITIES 101

SUMMER & SPRING DAYS: LOADS AND MUST TAKE RESOURCES



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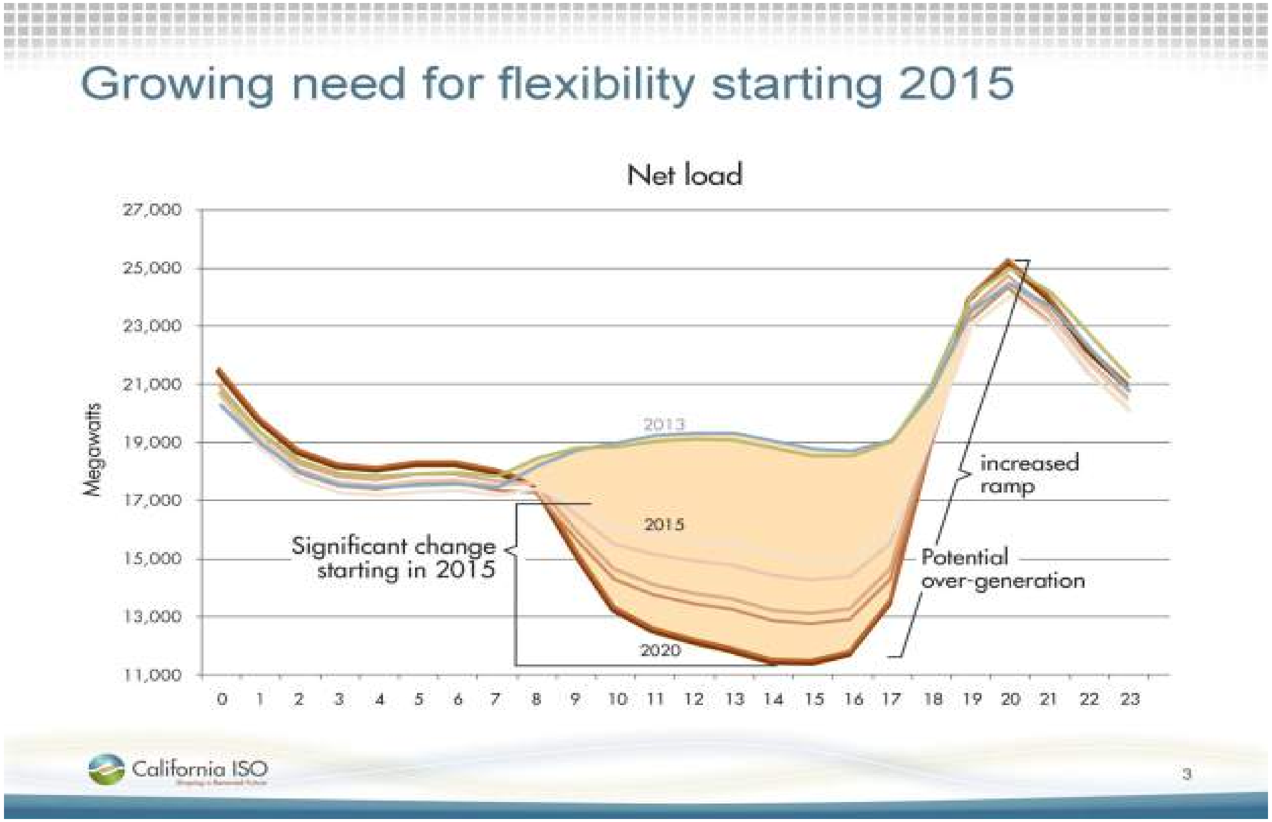
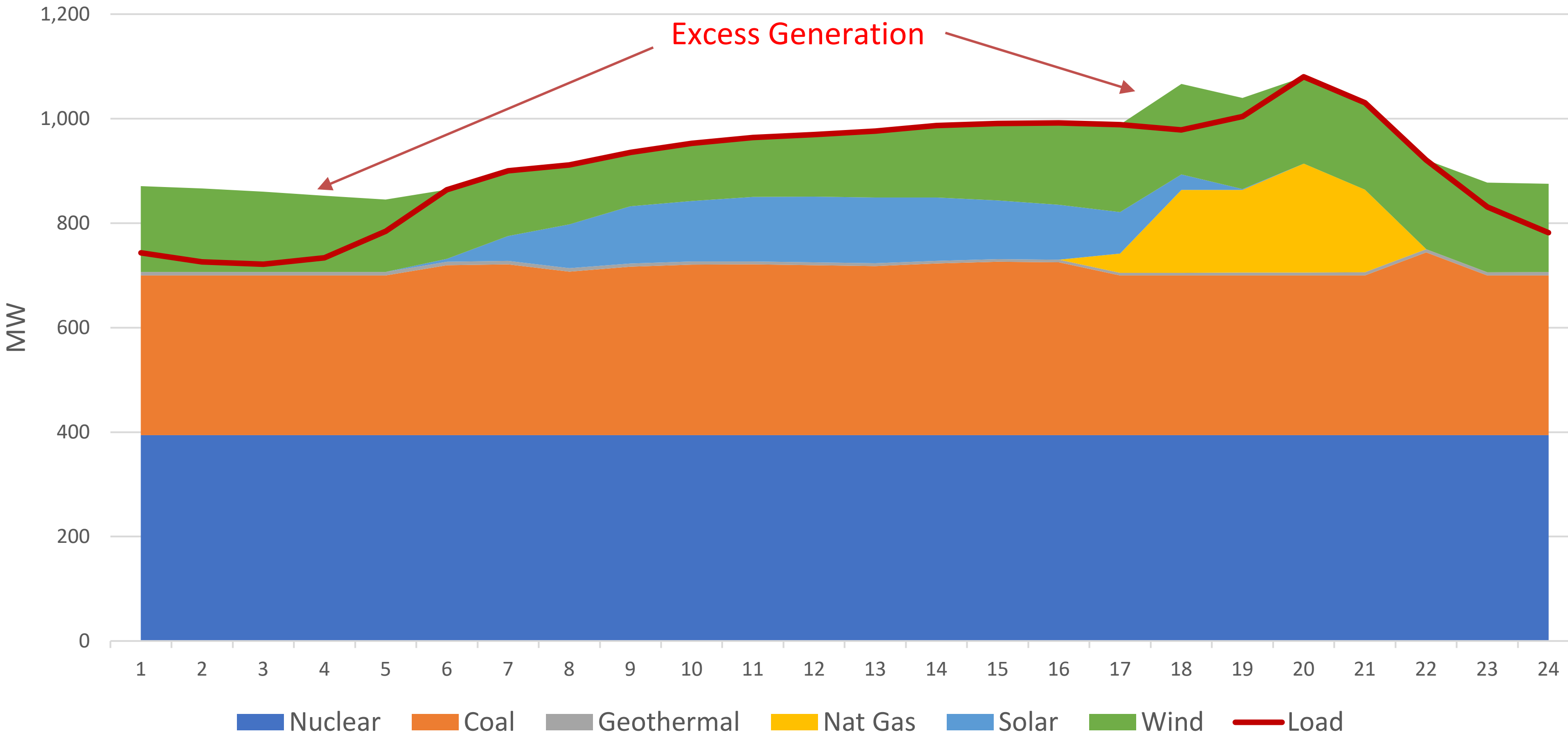
UTILITIES 101

NET LOAD



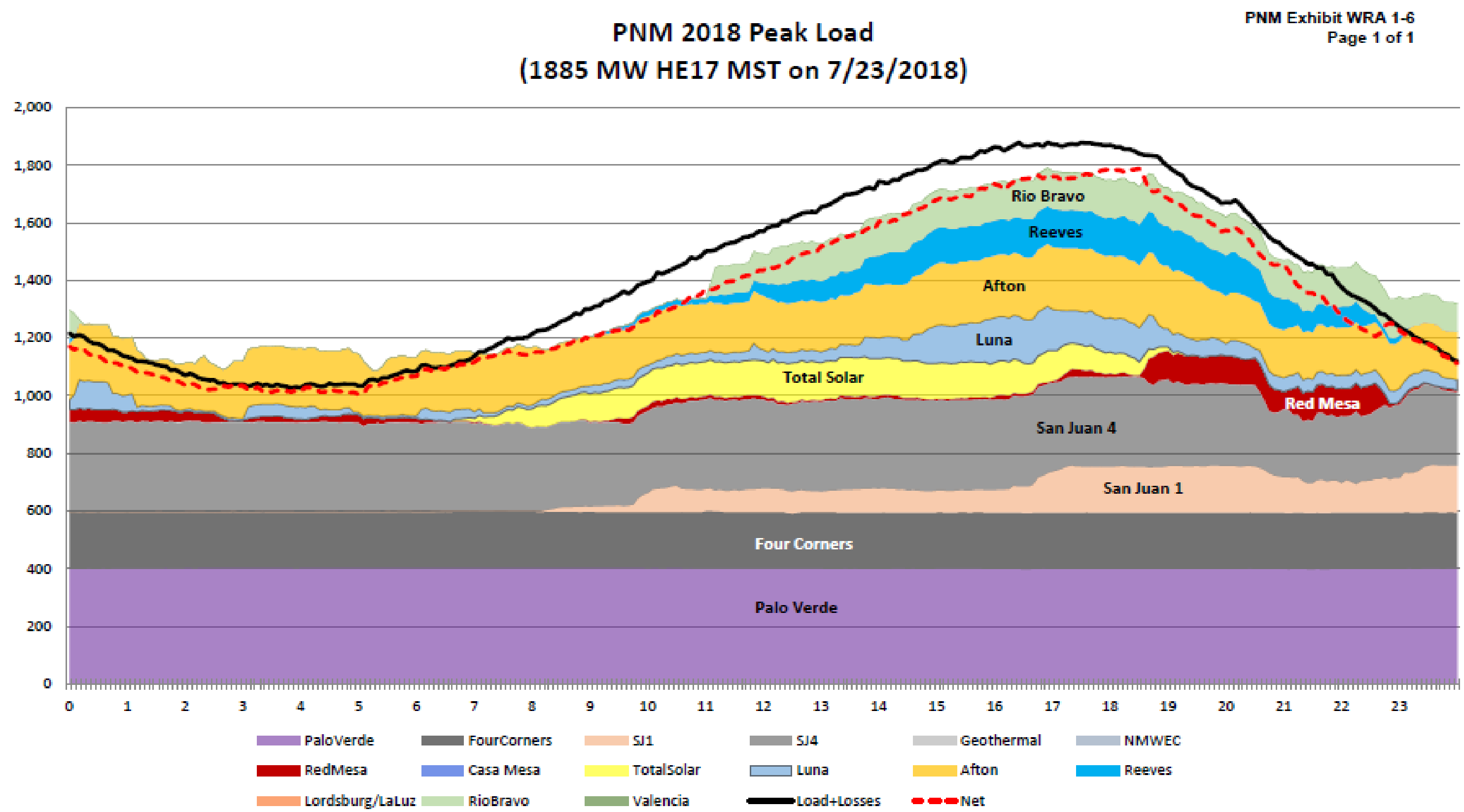
UTILITIES 101

DISPATCH STACK - APRIL



UTILITIES 101

DISPATCH STACK – PEAK DAY

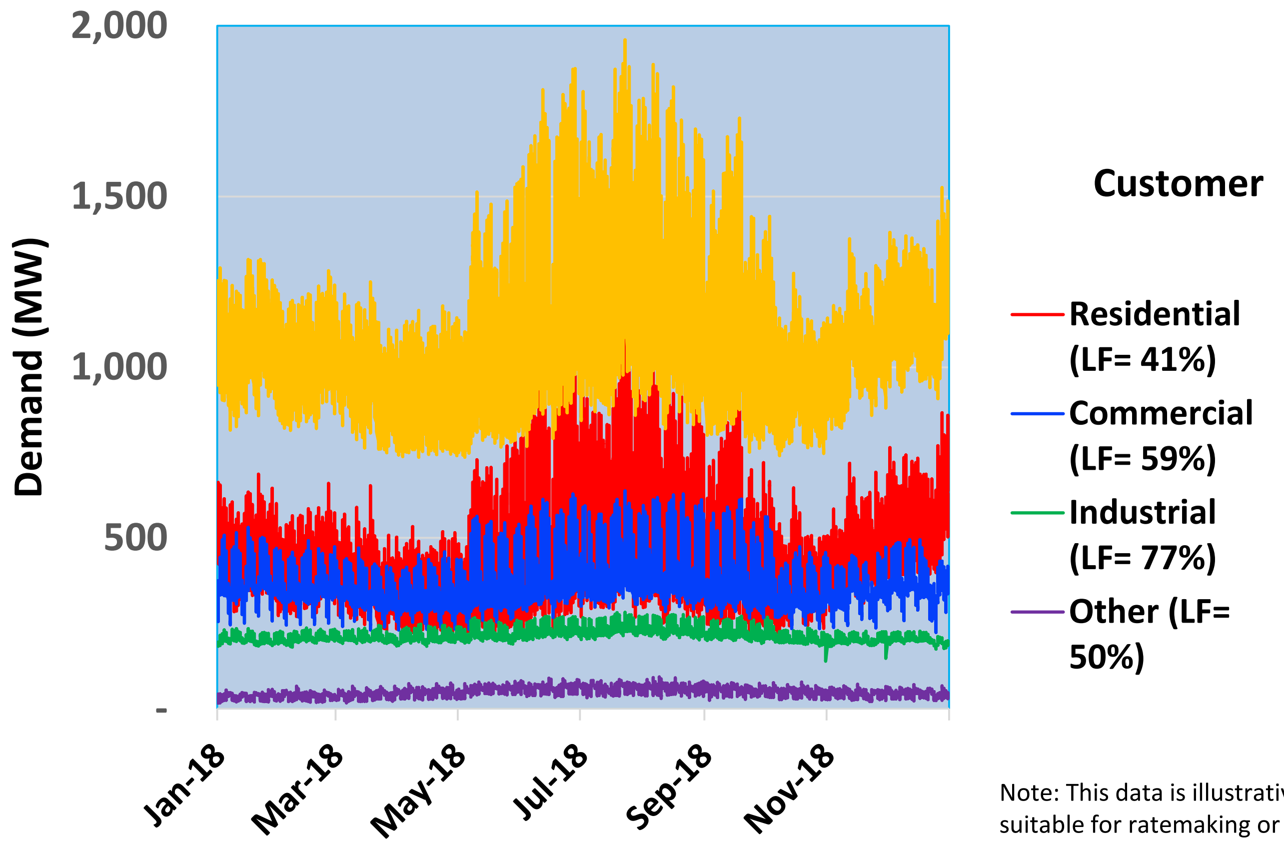


UTILITIES 101

CUSTOMER CLASS LOADS

UTILITIES 101

CUSTOMER CLASS LOADS



Note: This data is illustrative and is not suitable for ratemaking or other purposes

Talk to us.

CUSTOMER LOADS

Load factor

- Relationship between customer demand and energy usage

- LF = average demand / peak demand

- LF = annual energy / (peak demand * 8760)

- System Load Factor on Slide 16 (PNM BAA) is 56% (1,100 MW / 1,956 MW)

- Customer Classes Vary: On the previous slide, the System is a 56% load factor, but Residential is only 41%, Commercial is 59%, and Industrial is 77%

UTILITIES 101

CUSTOMER LOADS

Why is load factor important?

- Load factor can indicate how efficiently a customer (class) utilizes facilities installed to meet maximum demand

- Most fixed costs are related to demand as this directly relates to generation capacity (not energy)

RATE MAKING

REVENUE REQUIREMENT, RATES & COST RECOVERY

Rate Setting Process:

(1) Revenue Requirements – How much revenue do I need?
(2) Allocation of Costs – Who should be responsible for providing that revenue?
(3) Rate Design – How am I going to recover that revenue?

The revenue requirement represents the total cost of providing service
This cost must be allocated among:

(1) Customer classes (homogeneous groups of customers with regard to quantity consumed, load characteristics, voltage of service, and so forth)
(2) Products (retail vs wholesale)
(3) Services (fully bundled, distribution only, backup/standby, interruptible)

Cost allocation determines Revenues, and Consequently, average price, to be collected from each class of customers

UTILITIES 101

REVENUE REQUIREMENT, RATES & COST RECOVERY

Rate setting process

Revenue Requirement

- Compares the revenues of the utility to its expenses to determine the overall level of rate adjustment

Cost of Service

- Equitably allocates the revenue requirements between the various customer classes of service

Rate Design

- Design rates for each class of service to meet the revenue needs of the utility, along with any other rate design goals and objectives

UTILITIES 101

REVENUE REQUIREMENT, RATES & COST RECOVERY

Functionalization of costs

- Generation
- Transmission
- Distribution
- General (administrative, etc.)

Classification of costs

- Energy-related costs (e.g., costs varying with the amount of electricity consumed during a period of time, i.e., KWh)
- Demand-related costs (e.g., generation and transmission cost of providing electrical capacity to customers as required; a function of kW)
- Customer-related costs (e.g., costs varying with the number of customers, including meters, service drops and customer accounting and information expenses)

UTILITIES 101

REVENUE REQUIREMENT, RATES & COST RECOVERY

Cost Function	Cost Classification
Generation	Demand-Related Energy-Related
Transmission	Demand-Related
Distribution	Demand-Related Customer-Related
Customer Service (e.g., retail service)	Customer-Related

UTILITIES 101

REVENUE REQUIREMENT, RATES & COST RECOVERY – RATE DESIGN

Allocation of Costs to Classes - Class Cost of Service Studies

- Any allocation scheme involves some policy and subjective decisions
- Interest groups are expected to propose allocation methodologies that favor themselves
- There is generally no uniquely correct way to allocate costs

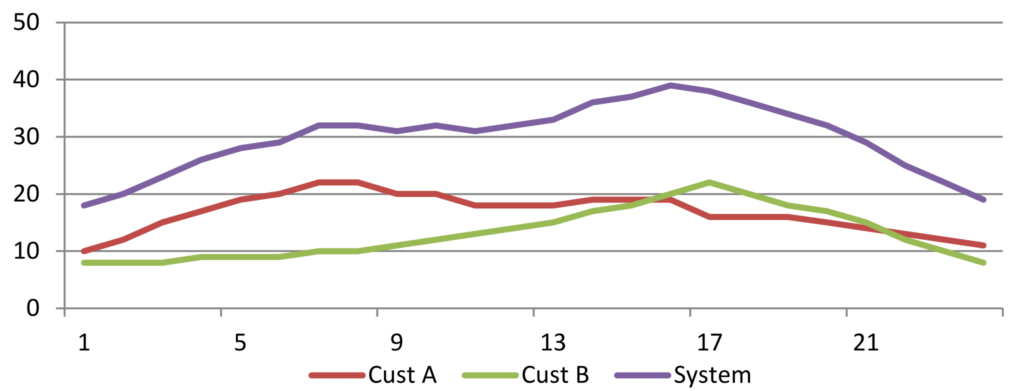
- Average Use (Energy) — allocate equal amounts of costs to each unit of output
- Peak Responsibility — allocate generating capacity based on share of the load at system peak (coincident peak method)
- Maximum Demand — allocate based on class or customer peak whether at system peak or not (non-coincident peak method)

UTILITIES 101

REVENUE REQUIREMENT, RATES & COST RECOVERY – RATE DESIGN

Two measures of demand – **coincident peak** vs **non-coincident peak**

- Depends on time of peak demand
- Coincident peak looks at when the combined system is peaking – this generally drives investment in generation and transmission
- Non-coincident peak looks at individual customer or class peaks – this generally drives investments in the distribution system



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REVENUE REQUIREMENT, RATES & COST RECOVERY – RATE DESIGN

Allocation of Costs to Classes

Assume that individual class demands at the time of system coincident peak is as follows:

Residential	2,000 MW	(42%)
Commercial	1,500 MW	(31%)
Industrial	1,300 MW	(27%)
Total System	4,800 MW	

If total generation plant (embedded) costs are $50 million, the cost allocation would be as follows:

$21.0 million to the residential class

$15.5 million to the commercial class

$13.5 million to the industrial class

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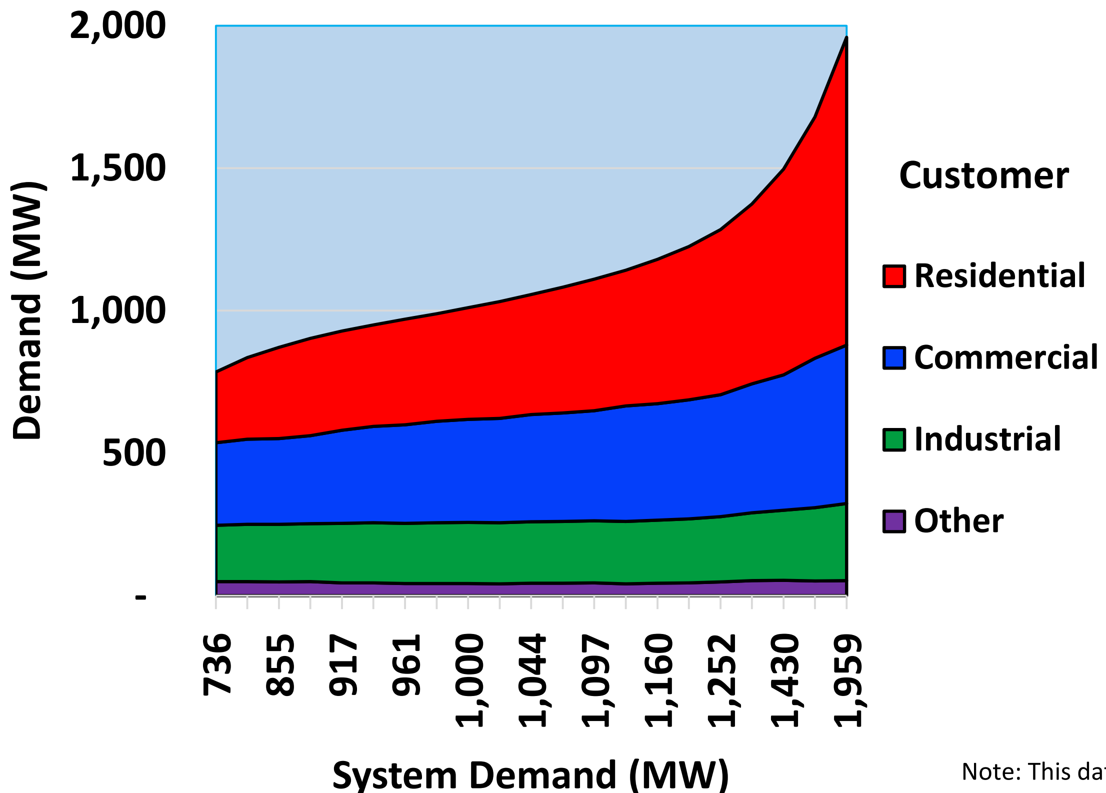
REVENUE REQUIREMENT, RATES & COST RECOVERY – RATE DESIGN



Note: This data is illustrative and is not suitable for ratemaking or other purposes

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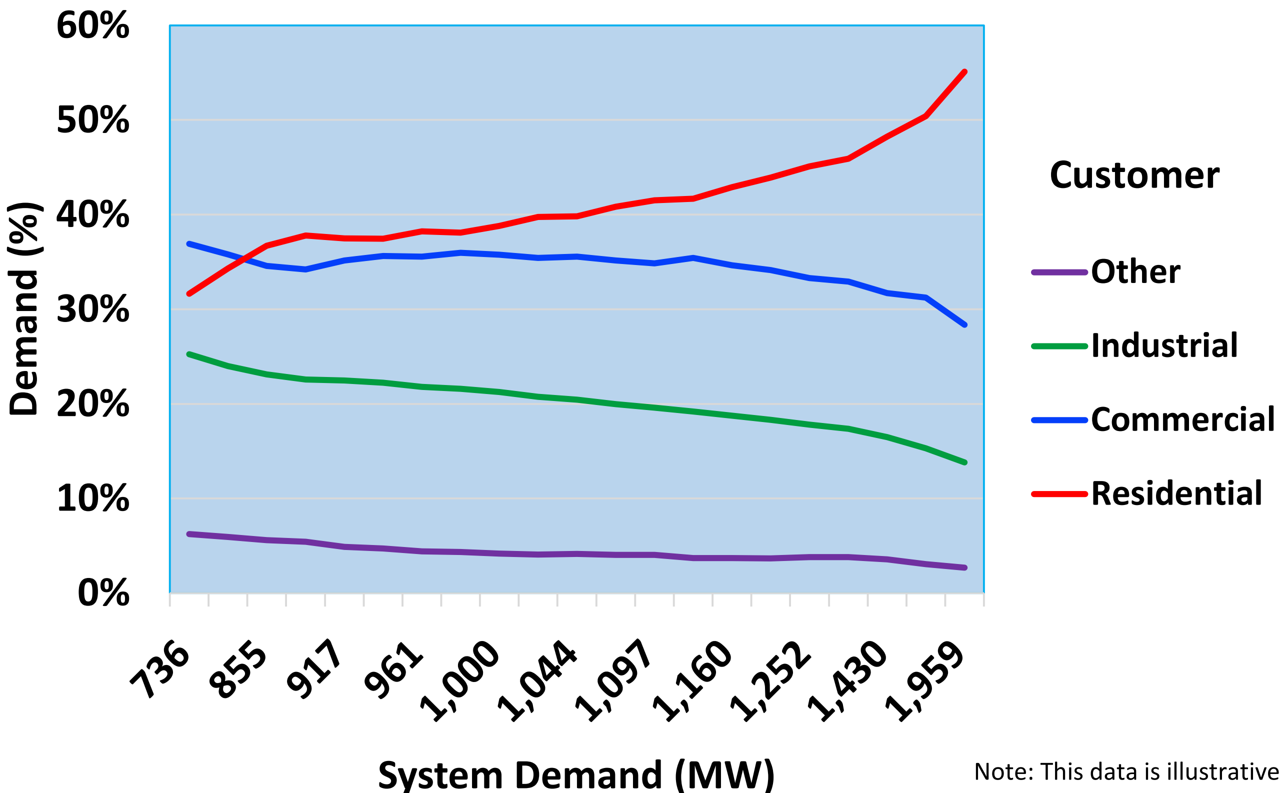
REVENUE REQUIREMENT, RATES & COST RECOVERY – RATE DESIGN



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REVENUE REQUIREMENT, RATES & COST RECOVERY – RATE DESIGN

Cost allocation determines how many dollars to collect from various classes or services

- Rate design determines how to collect dollars from various customer groups and services
- Like cost allocation, rate design is as much art as science
- Pricing principles provide a foundation for rate design
- A good rate design, for example, reflects principles of cost causation, which promote both economic efficiency and certain equity goals

Comments

- It is often difficult — or impossible — to achieve all these goals at once
- Almost all real-world rate designs are compromises
- Certain goals may be conflicting
- Rates that are efficient may not be considered fair

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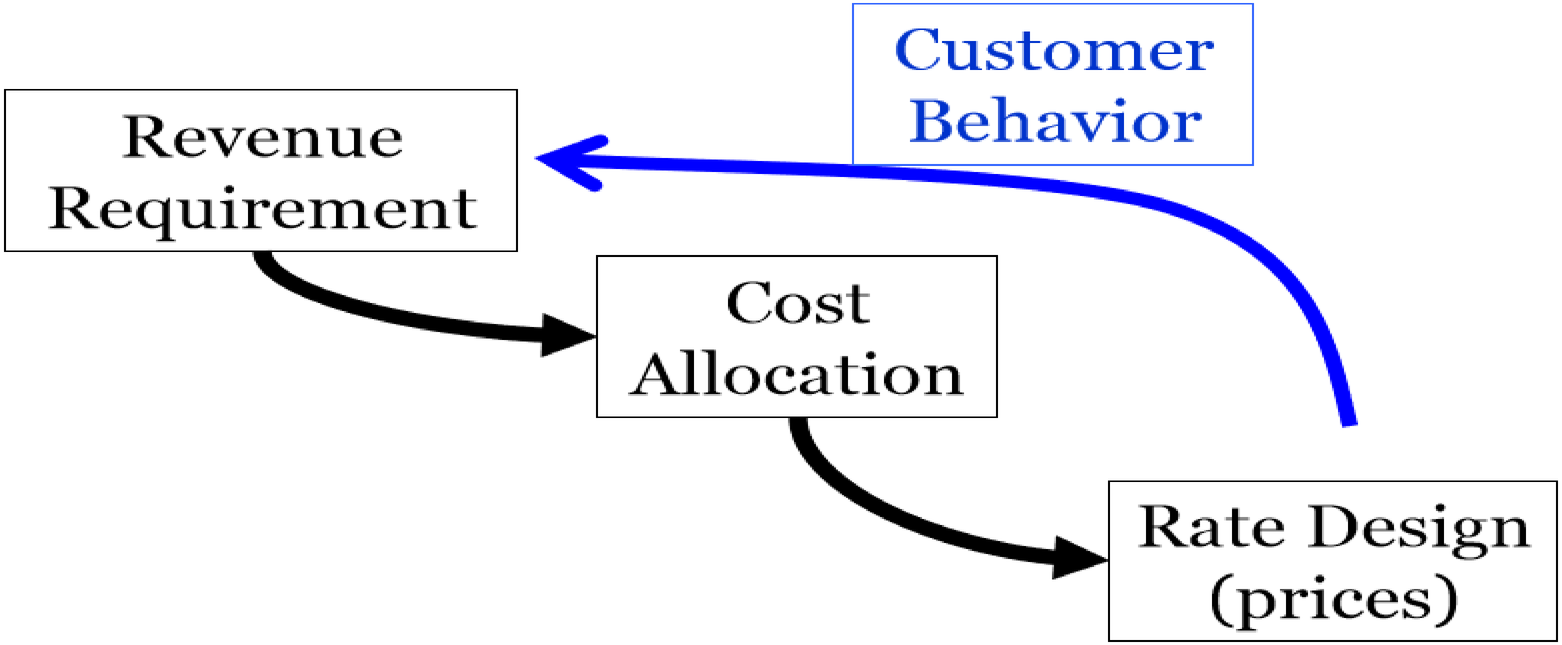
REVENUE REQUIREMENT, RATES & COST RECOVERY

Ratemaking Feedback Loop



REVENUE REQUIREMENT, RATES & COST RECOVERY

Components of Rates & Sample Bill

- Customer Charge ($/Month)
- Covers basic fixed cost of serving a customer (e.g., cost of customer hook-up)
- Meter reading, billing, etc.
- Charge for basic facilities used to provide service

- Capacity or Demand Charge ($/kW)
- Covers cost imposed on the system by the user's maximum load or usage
- Usually excluded for residential service but has gained much attention recently

- Usage Charge ($/kWh)
- Covers incremental cost of each unit of service
- In principle, usage charges should recover only usage-sensitive costs

SAMPLE BILLS

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SAMPLE BILL - RESIDENTIAL

Cheaper Block 1

More Expensive Block 2 – Promotes Conservation

YOUR CURRENT ELECTRICITY CHARGES							
Meter Read	Meter Read Date	Days Billed	Meter 0855298 Present	Previous	Meter Constant	Total kWh	Rate
Actual	03/14/2019	30	19649	- 19067	X 1.000	= 582.000	1A

Electricity You Used	Block 1		450.000 kWh@ $ 0.0779432	$35.07
	Block 2		132.000 kWh@ $ 0.1070240	$14.13
Fuel Cost Adjustment:				
Non-Renewable: 81.2% of kWh			472.584 kWh@ $ 0.0225528	$10.66
Renewable: 18.8% of kWh			109.416 kWh@ $ 0.0000000	$0.00
Renewable Energy Rider			582.000 kWh@ $ 0.0071959	$4.19
Customer Charge				$7.11
Cost-Effective Energy Saving Prog.		3.202%		$2.27
City/County Franchise Fee		2.000%		$1.47
Gross Receipts Tax				
State		5.1250%		$3.84
County		1.1875%		$0.89
City		1.5625%		$1.17
Current Electricity Charges				**$80.80**

YOUR BUDGET BILL		
Budget Bill Balance	-$53.87	
Current Budget Bill Payment Amount		**$127.00**

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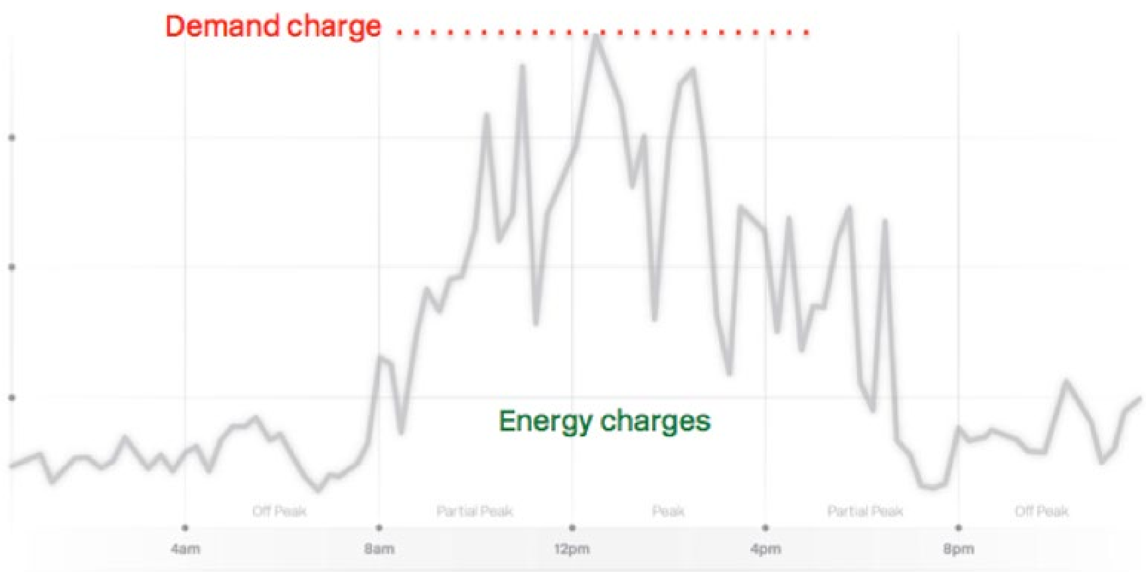
ENERGY VS DEMAND CHARGES

1 Energy charges
Total kWh used

2 Demand charge
Highest 15-minute kW peak



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SAMPLE BILL – COMMERCIAL/INDUSTRIAL

On-Peak & Off-Peak Energy & Fuel Charges

Demand Charges

YOUR CURRENT ELECTRICITY CHARGES

Meter Read	Meter Read Date	Days Billed	Meter 0581736 Present	Previous	Meter Constant	Total kWh	Rate
Actual	04/23/2019	32	5642	- 5431	X 1200.000	= 253200.000	4B

Large Pwr 4B TOU - Cust XFMR - EN11			
Percent of kWh Used On-Peak		37.44%	
On-Peak Use and Charge		94,800.000 kWh@ $ 0.0237302	$2,249.62
Off-Peak Use and Charge		158,400.000 kWh@ $ 0.0156946	$2,486.02
On-Peak Fuel Cost Adjustment:			
Non-Renewable: 80.4% of kWh		76,219.200 kWh@ $ 0.0149672	$1,140.79
Renewable: 19.6% of kWh		18,580.800 kWh@ $ 0.0000000	$0.00
Off-Peak Fuel Cost Adjustment:			
Non-Renewable: 80.4% of kWh		127,353.600 kWh@ $ 0.0149672	$1,906.13
Renewable: 19.6% of kWh		31,046.400 kWh@ $ 0.0000000	$0.00
On-Peak Renewable Energy Rider		94,800.000 kWh@ $ 0.0071959	$682.17
Off-Peak Renewable Energy Rider		158,400.000 kWh@ $ 0.0071959	$1,139.83
Customer Charge			$585.29
Demand Reading	**0.390**		
Actual Demand: (Read x Constant)	468.000		
Billable Demand	500.000		
Billed demand and charge	500.000	@ $16.4900000	$8,245.00
Rkva Reading	**0.360**		
Actual Rkva (Read x Constant)	432.000		
Allowed Rkva (48% of Billable Demand)	240.000		
Billed Rkva and Charge	192.000	@ $ 0.2700000	$51.84
Cost-Effective Energy Saving Prog.	3.202%		$591.95
City/County Franchise Fee	2.000%		$381.57
Gross Receipts Tax			
State	5.1250%		$997.34
County	1.1875%		$231.09
City	1.5625%		$304.07
Current Electricity Charges			**$20,992.71**

Talk to us.

INTEGRATED RESOURCE PLAN SCHEDULE

THREE PUBLIC ADVISORY PHASES, ONE DEADLINE

- July – October 2019: Build assumptions and discuss scenarios and sensitivities
- November – February 2020: Discuss analysis plan and discussion of findings
- March – June 2020: Discuss draft report
- July 1, 2020 – File report documenting the Plan and process with New Mexico Public Regulation Commission

NEAR TERM SCHEDULE

TENTATIVE MEETING SCHEDULE THROUGH JANUARY

July 31, 2019:	Kickoff, Overview and Timeline
August 20, 2019:	The Energy Transition Act & Utilities 101
August 29, 2019:	Resource Planning Overview: Models, Inputs & Assumptions
September 6, 2019:	Transmission & Reliability (Real World Operations)
September 24, 2019:	Resource Planning "2.0"
October 22, 2019:	Demand Side/EE/Time of Use
November 5, 2019:	Load & CO_2 Forecast
December 10, 2019:	Technology Review/ Finalize scenarios based on technical advisory group input
January 14, 2020:	Deadline for Scenario Requests

MAKE SURE WE HAVE UP TO DATE CONTACT INFORMATION FOR YOU

www.pnm.com/irp for documents

irp@pnm.com for e-mails

Register your email on sign-in sheets for alerts of upcoming meetings and notices that we have posted new information to the website.

Meetings Schedule:

Tuesday, August 20, 2019, 1:30 p.m. to 4:30 p.m.

Tuesday, August 29, 2019, 1:30 p.m. to 4:30 p.m.

Tuesday, Sept. 6, 2019, 1:30 p.m. to 4:30 p.m.

Thank you

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