FMPA Capacity Needs and Options to Defer: Load Management Workshop

FMPA Executive Committee

4/14/2021

Load Management Can Displace Higher Cost Alternatives

Proposed Implementation Program Will Benefit All ARP Members

- Intention of the proposed program is to pursue load management (LM) alternatives to meet short and long-term requirements of the ARP Project
- Given modifications to the ARP demand rate, a load management program can be established that adds value for Members, without shifting costs
  - FMPA/ARP drives utilization for benefit of entire ARP
- As need increases, different forms of load management will be utilized that can be compensated outside of demand billing
  - Meter specific load management resources; compensate distinct from demand billing
- There is no intention to pursue the types of load management where there is disparity between levels of capabilities in the Membership

ARP Has Capacity Needs Now and Beyond 2027

Step One is Understanding Member's Capabilities for Load Management

- Staff has maximized ARP capacity through 3rd party sales & now requires short-term resource management
  - Seasonal load shapes create pockets of small needs that load management (LM) could satisfy
  - Planned plant outages also create similar opportunities
- Longer-term, the ARP capacity purchase contracts from Oleander and Stanton A expire, creating a need for replacement capacity
  - FMPA's supply reductions require ~40 – 120 MW of capacity post 2027
  - New build alternatives are limited and can be expensive
- Given a ~5 year planning horizon, FMPA will soon need to understand its Members' ability to "Load Manage"
- Staff looking to understand potential quantity and terms of use for two major types of Member Load Management

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Phased Development of Program Ensures Value for All

Load Management Staged to Align with Overall ARP Need

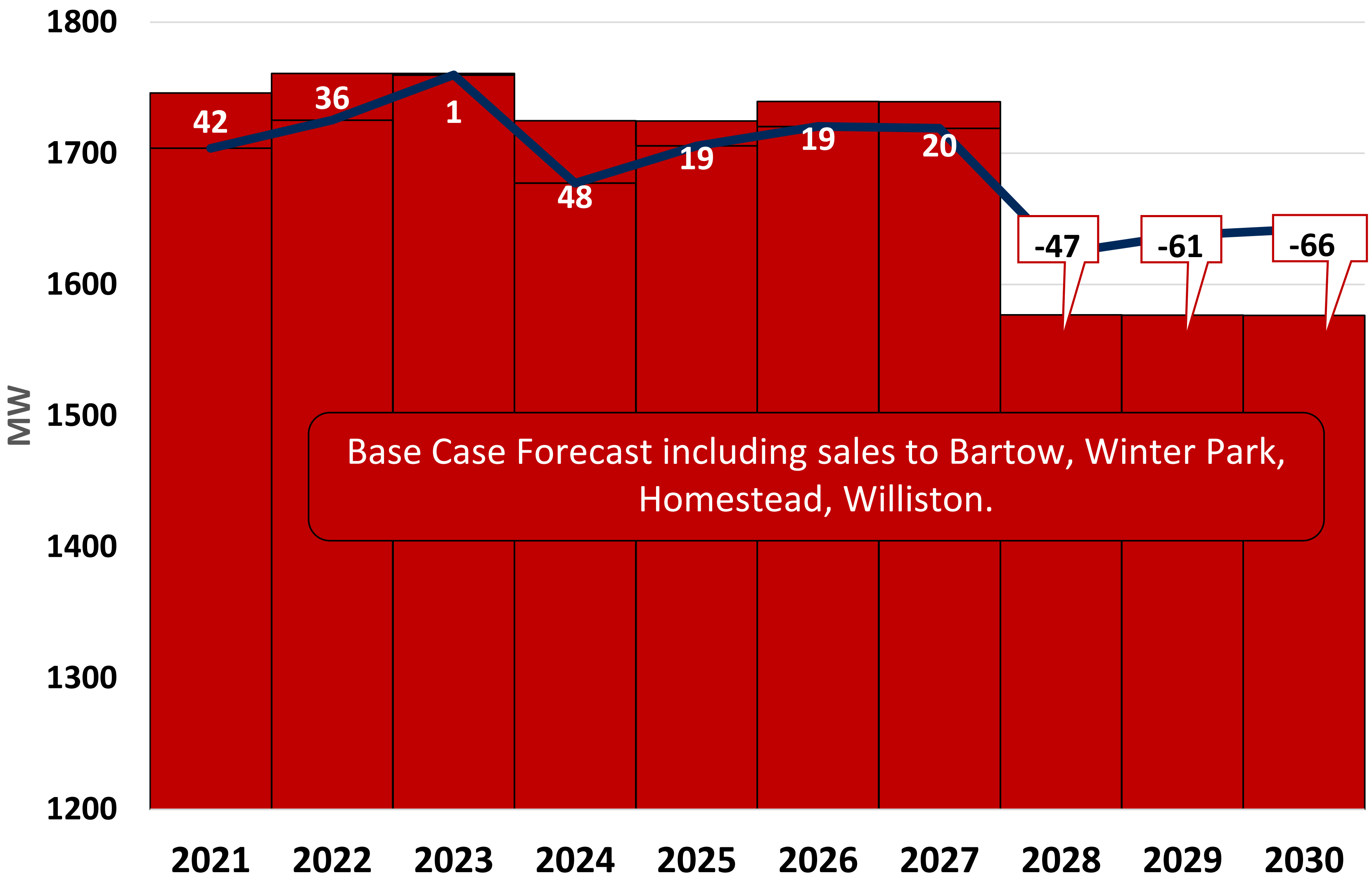
FY21-22	~FY23-FY26	>FY27 if Cost Justified	
Phase One Member owned equipment and loads Explore capabilities	**Phase Two** Member owned generation	**Phase Three** Large retail generation Large retail curtailment	**Phase Four** Broad retail program for customer owned loads

Need & Value Drivers

New Resources Require Significant Lead Time & Cost

Load Management Understanding Must Start Early to Add Value

With up to a five-year lead time to build new generation assets, there is significant cost to the uncertainty of being wrong on the timing.



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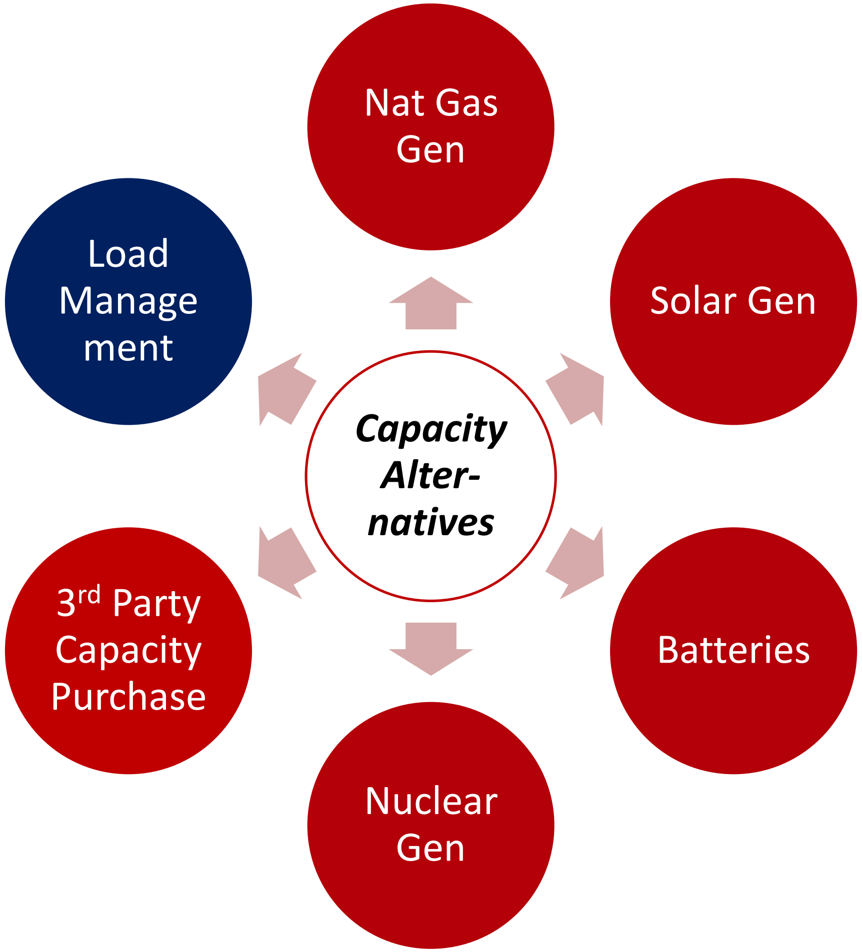
Load Management an Economically Viable Option

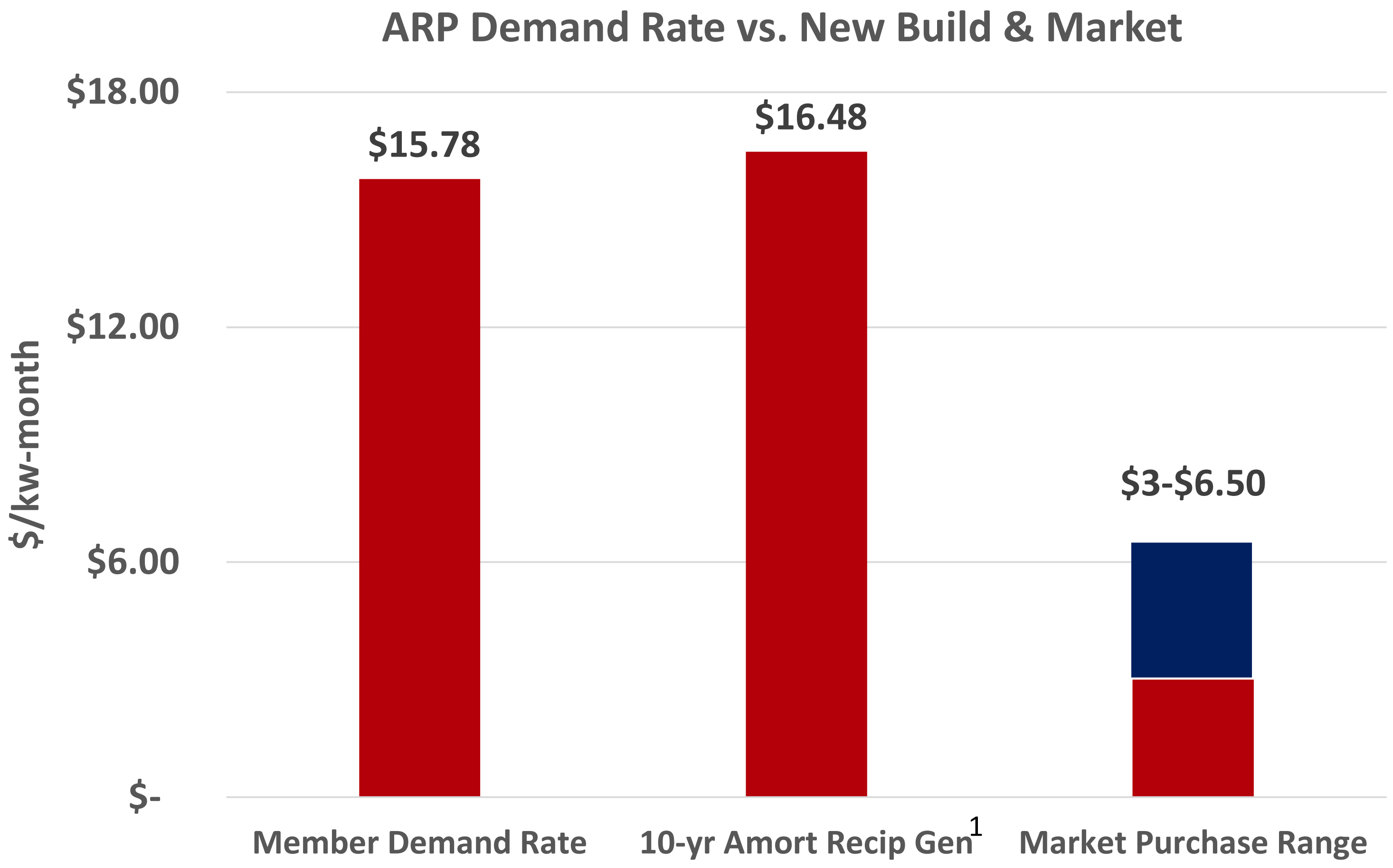
ARP Load Management Reduces Capacity Need Long Term, Sold Near Term

- Load management is a form of capacity, & therefore value, for the ARP
  - Long-term reduces capacity of higher cost PPA or new build
  - Near-term reduces the need for 3rd party short-term reserve purchases
  - Near-term creates new value through additional capacity sales lowering ARP costs



Beyond ST Management, Long-term LM Displaces New Build

LM Provides More Certainty Than Exposure to Market Price Risk & Volatility



Market purchases may be an option, but carry price and market depth risks with high degree of volatility.

1 – Recips include fixed costs

Additional Potential Value from Load Management

Viable Alternatives to Markets or Construction Should Be Pursued

- Gradual build of load management can limit risks of
  - High-cost short-term capacity purchases for FMPP 10% day-ahead reserve
  - Managing FMPA's transmission area specific shortages
- Solar buildout will drive value for peaking capacity and ancillary service products for FMPP pool
  - In certain instances, load management may be lower cost alternative to startup costs of larger gas units
- Aging generation fleet availability may change

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Prudently Phased Implementation Approach

Staff Must First Explore the Potential Capabilities

Process Development To Be Driven Based on Available Options

FY21-22	~FY23-FY26
Phase One	**Phase Two**
Member owned equipment and loads	Member owned generation
Leverage New Demand Rate	Compensate metered Gen at ~ Market

New Rate Structure Mitigates Cost Shifts

FY24 before the impact fully felt by ARP Participants

- ARP billed demand costs to Participants now are allocated based on Participants' average coincident peak (CP) demand during the summer months (June – September) over the prior 3 fiscal years
- At best, any demand management implemented in FY21 will not be fully felt in rates until FY24
- Anyone can participate
- Impacts known well in advance and can be offset

Current Conditions Incent Smaller Volumes of LM

Still Prudent to Explore Small Volumes and Establish Foundation for Future

- Staff would therefore target 5-10MW max during Phase 1
- The 3-yr rate structure averaging does mitigate by deferring into the future
- There is some risk of utilization of load management during peak periods in summer, but based on targeted volumes, cost shifts are immaterial
- Utilization of LM to meet a reserve need during a spring outage will have no impact on rates

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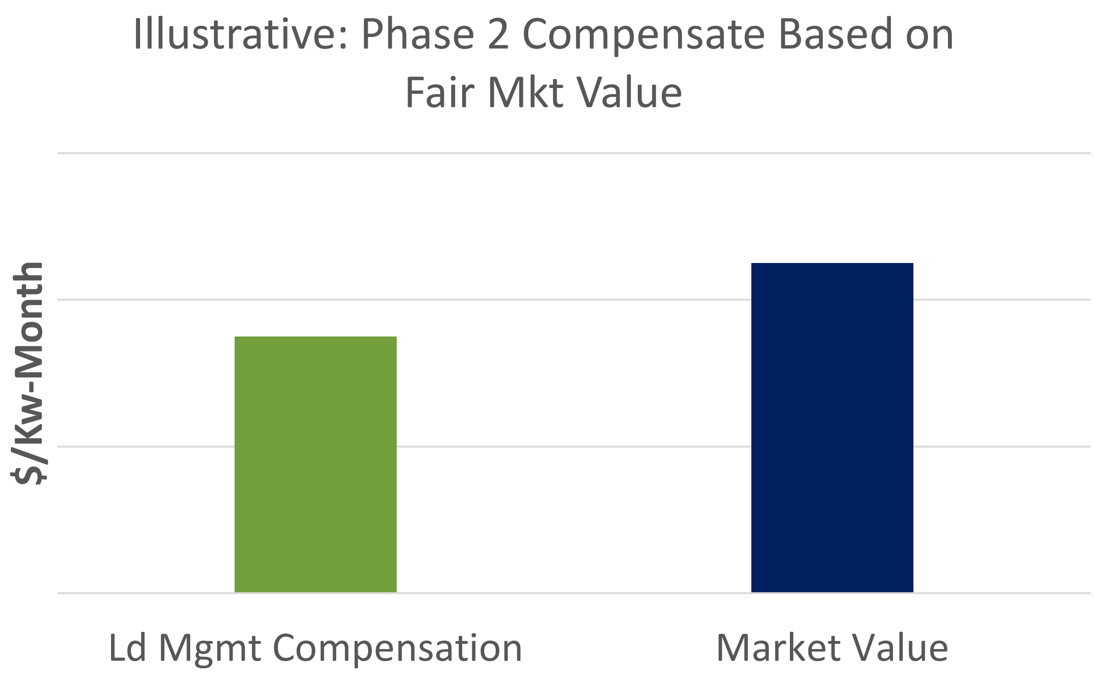
As ARP Underlying Need and Risks Increase Compensate to Market

Phase 2 Would Allow Long-term Mitigation Without Additional Cost Shifts



If uncertainty around new build or purchase need grows and short-term seasonal needs increase, it is prudent to look at controllable behind-the-meter generation.

Rather than compensate through reduced demand billing, compensate based on fair market value.

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Billing Offsets Could Make Program Net Neutral

LM Reducing ARP CP Could be Reimbursed at ~Market Thereby Mitigating Rate Impacts

- Thresholds could be set for maximum volume of load management that create cost shifts
- Controllable behind-the-meter generation that provides reserves or reduces ARP coincident peaks could be eligible for compensation
- Generation assets would be required to be metered & tested periodically
- Compensation mechanisms would be driven by verifiable market prices & cost of operation
- Members would be reimbursed based on utilization or reserves or operation while not providing any impact to demand rate billing
  - Demand added back if units operated thereby not impacting demand billing
- Staff will explore the potential need for structured agreements vs. defined rate billing mechanisms

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Types and Options for Load Management

There are many forms of Load Management

Complexity and cost can vary dramatically based on type of load reduction

Load Management Form	Complexity of Implementation	Typically Requires Retail Compensation	Included in FMPA Initial Efforts
Large Muni Owned Equipment / Loads	Low	No	Yes – Ph1
Behind the Meter Member Generation	Low	No	Yes – Ph2
Behind the Meter Large Retail Generation	Low	Yes	No
Large Commercial/Industrial Load Curtailment	Medium	Yes	No
Small Customer Owned Generation	High	Yes	No
Retail Load Control Aggregation (water heaters, pool pumps, etc.)	High	Yes	No

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Members and Staff Will Review Member Opportunities

“Simple” Peak Mitigation Alternatives First Priority

- Readily available load management alternatives would be target for near-term implementation at certain Load or Generation areas:
- Load Targets (FY21-FY23)
  - Example: Water Treatment Plant Equipment Curtailment or Optimization
- Generation – Targeted for emergency back-up and reserves (>FY23)
  - Member emergency generators – Lift stations, Waste Water plants, etc.
  - Member's Customer's Generation – Publix, other stores, hospitals, etc.

Staff Recognizes Emergency Generation Has Environmental Compliance Issues to Manage

- Primary targets for first phase do not include emergency generators or engines
  - Phase 1 focused on: Load management of city facilities
- Primary targets for second phase will include “behind-the-meter” generation that can be metered
- EPA’s RICE NESHAP may or may not apply to specific existing generator capabilities and prior deployment patterns
- In order to pursue this line of opportunity further, would likely require individual review for compliance on a case-by-case basis

Any Member Can Now Elect to Participate

FMPA staff can assist Members to mitigate cost shifts

City	Volume to Fully Offset FY24 1MW Cost Shift (kW)
Havana	4.0 (kW)
KUA	286.9
Key West	109.8
Green Cove Springs	19.4

- Options can be explored for every member to participate at some level in some form of demand management
- This in turn can provide additional new revenues for overall ARP
- FMPA goal for FY21 was 5MW

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Capacity "Additions" Creates New Margin Opportunities

ARP Will Have Net Benefit in Monetizing Additional "Supply"

- Long-Term Capacity Sales Opportunities
  - Alachua: 2022
  - Bartow: 2024
  - Wauchula: 2024
  - Moore Haven: 2026
  - Lakeland – to replace part of coal retirement?
- Short-term Sales Opportunities
  - Seasonal TECO sale
  - Monthly JEA/GRU type sales
  - Extensions of existing tolling agreement with Reedy Creek
  - Seasonal sales to FMPP to cover outages or as bridge to new resources

Staff Will Sell or Utilize Load Management MWs

Past efforts to monetize surplus capacity have reduced ARP rates

- Current market value of capacity sales
  - Intra month during outages ~ $1.00/kW-mo.
  - Monthly $1.00/kW-mo.
  - Seasonal - $1.00 - $3/kW-mo.
  - Longer-term - $2.50 -$4/kW-mo.
- Leverage relationship with TEA to expand potential transaction partners and opportunities

Next Steps

Preliminary Implementation Overview

Steps Required to Restore the Demand Management Program

- Meet with all ARP participants to capture full perspective of load management capabilities
- Quarterly progress reports to EC
- Fuse into load forecast and capacity plan/TYSP

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FY21 Goals Primarily an Assessment of LM Potential
Can Staff Identify 5-10MW Member Controllable Loads?

- Identify LM potential
- Target 5MW, but no more than 10MW for Phase 1
- Work with members on process for utilization
- Work with FMPP to ensure LM can be utilized against reserve requirements
- Identify any metering or tracking required to appropriately assess implementation
- Begin to quantify available behind-the-meter generation
- Seek Executive Committee approval of Phase 1 plan and deployment

Moving Forward Requires ARP Motion

The May 2014 Motion Prohibits Action on Demand Management

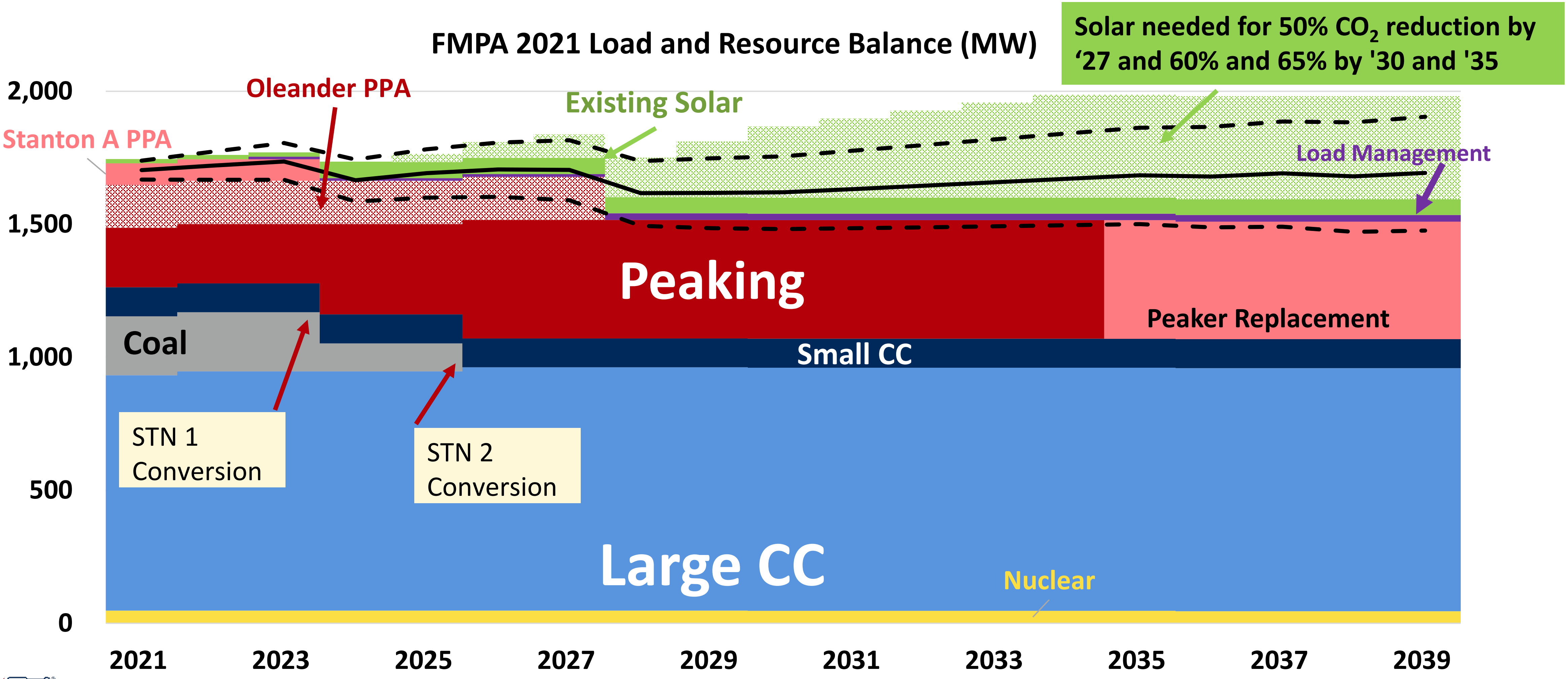
- In May 2014, the Executive Committee Approved the following action:
  - "After September 30, 2014 ARP Participants **will not engage** in continuous voltage reduction measures or deploy ARP Participant owned emergency generation **to intentionally reduce system demand costs**. After September 30, 2015 ARP Participants will not deploy customer emergency generation to intentionally reduce the ARP Participant's system demand costs. After September 30 2014 each ARP Participant must notify FMPA within 10 days each time any of its electric generators are operated above or beyond routine operational testing. It is not the intent of this proposal to limit any Participant's management of its retail electric systems in a manner to provide reliable electric service to its retail customers, particularly during responses to emergency events such as hurricanes, tornados, tropical storms or other system destructive events. This includes actions taken for local system reliability or during periods in which the FRCC Reliability Coordinator or the FMPP Balancing Authority or the ARP Participant's Transmission Operator has declared an Energy Emergency Alert Level 2 (EEA Level 2) as defined in the North American Electric Reliability Corporation Reliability Standard EOP-002-3, Capacity and Energy Emergencies. Nor does this proposal apply to any ARP Participant retail customer that delivers power to the ARP Participant pursuant to a net metering arrangement, as provided for in the ARP net metering program."

- This policy decision needs to be revisited by EC in order to fully implement benefits associated with the new demand rate restructuring.

Appendix

ARP's Growth Can Eventually Require Capacity

Significant Uncertainty Exists Around Long-Term Forecasts



HVA’s Cost Change <1.5%* Thru FY24 For 5 MW

Phased 3-year Approach Mitigates the Overall Impact

FY	Phased in Volume (MW)	Net ARP Shift ($)[1]	HVA % of ARP Demand	HVA Annual Impact ($)	HVA Increase in Demand Charge (%)
2021	0	$150,000	0.403%	$604	(0.06%)
2022	1.7	($165,600)	0.403%	($667)	0.07%
2023	3.3	($481,200)	0.403%	($1,938)	0.21%
2024	5	($796,800)	0.403%	($3,208)	0.34%

1 – Includes ability to monetize surplus at $2.50/kw-month

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