EPE 2025 Integrated Resource Plan
ACTION PLAN - STAKEHOLDER INPUT
FOR REFERENCE
July 2025

Stakeholder input regarding action plan items are included in this document. Please see the Action Plan Discussion Guide for Workshop #8 for a summary of both stakeholder suggestions and EPE action plan items.

Comments Received - Duplicative suggestions have been consolidated and some statements may have been summarized for brevity.

CCAE (Cara Lynch) & SWEEP (Ramon Alatorre)

Residential Demand-Side

- Robust enrollment, stakeholder engagement: significant customer education and engagement to drive enrollment in the TOU/TOD tariff. We support the current 12-month no-risk feature.
- Make the TOU tariff the default tariff for new customers (with an opt-out option) perhaps starting in 2027.
- EPE should also explicitly connect the forecasted DSM/DER outcomes of the scenario to the next EE/LM Plan filing (2027).
- HB 13, the initial Distribution System Plan (DSP): should include VPPs and NWAs

C&I Demand Response

- Supportive of draft recommendations of Stephen Fischman

Social Cost of Carbon

- SCC included as an “informational adder” for each scenario?

Steve Fischmann

Eddy Tie

- Model and analyze potential benefits of enlarging the Eddy HVDC tie beyond 200 MW

C&I Demand Response

- Incorporate C&I demand resource management into an all- customer class Strategic Demand Resource initiative to develop and implement 300 MW of Demand Side accredited resources by 2029.
- Develop a C&I demand resource plan – including rate structures- to incorporate into a targeted RFP for future C&I demand resources.
- Establish opt out TOU rates for all C&I customers in the next rate- case. TOU rate differentials must be impactful enough to impact customer behavior and customer demand side investment.
- Provide incentives for fully automated demand response programs that are reliable during energy shortage events.
- By July 2026, develop a $KW value to the EPE system for demand side resources.

Include impacts on generation and T&D investment, operating expenses, line losses etc.
- Establish a network of approved vendors to design and implement automated demand resource/ DER solutions in collaboration with C&I stakeholders by January 2027.

Data Centers
- Require each new data center customer to provide Demand response capacity equal to 20% of their estimated peak system load prior to interconnection. Maintain 20% DR capacity as they grow. Can be DR on their own account or DR purchases elsewhere in the system.
- Develop and publish EPE's strategy for transmitting power to new Data Centers/Large Customers that interconnect years before long term generation resources are obtained to support them. Include an analysis of the short and long term impacts on transmission investment of co-locating data centers with new generation, and co-locating data centers with existing generation. Include impacts on transmission assets beyond immediate interconnection investment both short and long term. Publish by December 2025.

Residential Demand Side
- Incorporate residential demand resource management into an all- customer class Strategic Demand Resource initiative to develop and implement 300 MW of Demand Side accredited resources by 2029.
- Develop a residential demand resource plan – including rate structures- to incorporate into a targeted RFP for future residential demand resources.
- Establish opt out TOU rates for all residential customers in the next rate case. TOU rate differentials must be impactful enough to impact customer behavior and customer demand side investment.
- Design a harmonized suite of demand resource measures and concise education materials on how consumers can take advantage of them. Focus test implementation on stressed feeders to maximize potential savings through avoided or deferred distribution investment. Test implementation to begin by January 2027.
- Eliminate EE heating and cooling incentives for gas powered HVAC instead focusing on efficient heat pumps or swamp coolers to better balance seasonal loads, improve system load factors and lower kWh unit costs.

Social Cost of Carbon
- Develop a $per ton social cost of carbon figure for use in resource analysis by October 2025.
- Identify the social cost of carbon as a separate line item to the operating cost of all carbon emitting resources.
- Subtract the social cost of carbon as a separate line item from the cost of operating resources that reduce carbon emissions.
- Implement immediately.

Gas Prices
- Build price protections into natural gas purchase contracts to protect against emergency/ price gouging events like winter storm URI.
- Evaluate potential reduction of non-price protected gas purchases.
- Purchasing strategies should limit consumer exposure to sudden price spikes that create financial emergencies for low income folks. This can be worth reasonably priced "insurance" provisions in procurement contracts.
- Include a fuel purchasing strategy in the IRP. It's particularly important if the elimination of federal renewable incentives pushes resource acquisition towards natural gas.

Transmission & Distribution
- Identify the extent of Dynamic Line Rating implementation on EPE's transmission system. Specify lines where it is already installed. List specific short- and medium-term opportunities for further implementation. Publish in the IRP or by December 2025.

- Identify the extent of Advanced Power Flow Control installations on the EPE grid. Specify lines where it is already installed. List specific short- and medium-term implementation opportunities.Publish in the IRP or by December 2025.
- Identify other grid enhancing technologies that should be evaluated for future implementation. List specific short- and medium-term implementation opportunities.

Chris Hickman

Eddy Tie

- Consider a case going forward with a much larger scale wind contract (>70) through Eddy County
- Define a 'combined value' of wind + storage as has been defined for solar + storage to better characterize how the blend of these two resources can benefit the system and customers.

C&I Demand Response

- Focus efforts on technology enabled, fully automated solutions that provide EPE direct signaling control of the Demand Response resources without any human interaction, so they are a reliable, dependable part of the resource mix.
- Define a $/kW value for this value for this category based on the analysis to date. This value will provide a baseline for the development of appropriate programs.
- Work with stakeholders to create an effective Technical Assistance/Technical (TA/TI) Incentive program to enable support for third party organizations to support C&I customers to study their facilities and help them implement these automated technology solutions. (For example, building management systems). Most commercial customers do not have the background to evaluate, specify, procure or install appropriate systems that can interface with the utility effectively and the TA component of this program is crucial for it's success while the TI component helps them be able to offset the total cost of install.
- Explore different TA/TI incentives based on the participation of the customer facility's participation. (For example, there could be a different incentive offered for building that can perform more often and for longer duration. Rather than one static program that defines the number of events per year and their required duration per event, create at least two options showing there is more value and more incentive for customers that can participate in more events per year and for longer durations.
- Work with stakeholders and the commission to create a 'regulatory asset with a defined return over a defined period of time' or other regulatory structure for this program that allows the utility to earn on these investments in partnership with their customers.

Residential Demand Side

- Define the 'best case' for DERs. Duration of storage, hours for DR, etc. that would best serve EPE now and moving into the future so that thinking for solutions by vendors can be guided towards current and future needs vs historical needs.
- Define a committed MW number to DER over the next 10 years that EPE will procure
- Continue to define the incremental values streams that DERs can provide that Plexos cannot capture and provide stakeholders/commission these results.
- Develop strategic metrics for DER deployment. For example: (1.Targeted Deployment to defer or eliminate existing distribution feeder or substation upgrades by creating DER permanent load shift and supply. 2. Improved Utilization/Load Factor – Determine how to track DER deployments to show the feeder/substation/system utilization/load factor improvement. 3. Grid System Efficiency – Determine how to track and monitor the grid system efficiency improvements of DERs improving power factor and phase balance for a feeder/substation/system. Determine how these Grid EE effects are recognized by the commission in the existing, or new, EE requirements and how these results will be recognized by the commission in the EE portfolio which has been historically focused on site efficiency measure (lighting/HVAC/etc.) vs grid efficiency. 4. Resiliency – Determine

how to track overall community/customer resiliency of DERs. Deploying DERs will make specific sites/feeders/etc. resilient and capable of operation during grid outages and there should be a tracking mechanism for the number of customers/sites/etc. that are more resilient over time. 5. Social Justice – The impact of DER deployment toward low-income, affordable housing versus programs that have historically been utilized by affluent customers who could afford the pay the additional upfront, or other, additional or higher costs.) While there may be more metrics or considerations, this process over the next few years should clearly identify the impacts of deploying DERs for the utility, customers and regulatory objectives should be part of the process moving forward.

- Determine if appropriate to support immediate technical demonstrations of any technologies for these technologies to allow rapid deployment to develop the metrics and tracking.
- Work with stakeholders and the commission to create a capital PPA, or other regulatory structure, for DERs that allows the utility to earn on these investments in partnership with their customers. The utility has taken a major step forward in partnering with stakeholders in this process to explore new ways to more effectively engage with customers and improve overall system economics and performance through DERs and should have the opportunity to earn on these investments while also having the contractual ability to de-risk their deployment by having third parties assume this risk of deployment, operation and maintenance to mitigate risk to the utility and their customers.
- Define a combined value of Solar + Battery for DER. The defined value of Solar + Battery that has been completed to date represents the combined value of Solar + Battery in a central station configuration versus a DER configuration.

Social Cost of Carbon

- All cases submitted as part of this IRP process should define, as a note, the cost of carbon implications for the solution so that stakeholders have a legitimate number to consider in the adoption of any case/solution.

Gas w Carbon Capture

- These cases should provide some context for stakeholders. Implementing these measures has a direct impact on the output capability of the unit. The ‘de-rated’ value of the unit for implementing CCS should be documented to clearly show what the capable output of the unit is reduced to when implementing these measures.
- In addition, a comparison of the fuel used per MWH hour of production, with and without CCS, should be identified to clearly illustrate the impact on the efficiency of the unit for fuel conversion to energy with these measures implemented.

LDES

- Note: The round-trip efficiency of this resource needs to be clearly documented and analyzed as part of the analysis as each time it is charged and discharged, more than 50% of the energy is lost. While this type of resource has a high ELCC for longer-duration capability to serve in the event of a major grid outage, it is operationally very expensive to use with any frequency. As such, it becomes a ‘back-up measure’ due to its very high cost of operation.
- Need to understand more clearly how it would be implemented into the system. As it will have a maximum MW/MWH rating, where will it be installed in the grid and who/what will actually benefit from its limited output. In other words, it can only serve a small portion of the overall load, so where would it be implemented and how would it be operated in the system to provide value to all stakeholders or the system overall?

Kurtz-Downs Joint

T&D Investments

- EPE will institute by October, 2025 an on-going internal process to proactively review the cost-effectiveness and viability of incorporating Grid-Enhancing Technologies (GET) into all proposed and existing transmission and distribution resources.

- Grid-Enhancing Technologies to be considered shall include, but not be limited to, Dynamic Line Rating, Power Flow Control, and integration with Distributed Energy Resources.
- Any determination of cost-effectiveness and viability will include consideration of GET contributions to improving transmission capacity and efficiency, grid stability and operations, and deferring or reducing the need for new infrastructure. Viable, cost-effective technologies will be included as requirements in RFP's for new T&D resources.

Kurtz-Fischmann Joint

Emerging technologies

- Keeping Up with Emerging Technologies
  - Partner with NM IOUs and the PRC to issue an annual RFI to timely update generic resource costs and available generation, T&D, and demand management technologies in NM. Publish results protecting vendor identities on the PRC website.
  - convene on a semi-annual basis a group of EPE professionals, stakeholders and other interested parties where new technologies affecting energy resources can be shared and discussed

Phil Simpson

C&I Demand Response

- Take advantage of load reduction using DR & DER technologies to reduce the peak capacity required.
- In addition to peak demand reduction, develop initiatives to increase load factor by increasing off-peak load, on both a daily and a seasonal basis. Heat pumps are one example.
- Explore price-sensitive but time-insensitive applications that could utilize low-cost energy when available but not operate when energy is expensive.
- Utilize the example of and experience from the 2008 California Technical Assistance/Technical Incentive (TA/TI) program for C&I DR.
- Keep the program as simple as possible to maximize the fraction of deployment costs resulting in DR (vs. management)
- Upgrade automated controls to facilitate automatic (pre-negotiated) utility calls for DR.
- Incorporate C&I demand resource management into an all- customer class Strategic Demand Resource initiative to develop and implement 300 MW of Demand Side accredited resources by 2029
- Develop a C&I demand resource plan – including rate structures- to incorporate into a targeted RFP for future C&I demand resources.
- Establish opt out TOU rates for all C&I customers in the next rate- case. TOU rate differentials must be impactful enough to impact customer behavior and customer demand side investment.
- Provide incentives for fully automated demand response programs that are reliable during energy shortage events.
- By July 2026, develop a $KW value to the EPE system for demand side resources. Include impacts on generation and T&D investment, operating expenses, line losses etc.
- Establish a network of approved vendors to design and implement automated demand resource/ DER solutions in collaboration with C&I stakeholders by January 2027.

Residential Demand Side

- Encourage the deployment of heat pumps by educating and incentivizing customers, equipment wholesalers, and heat pump installers. The perfect time for heat pump installation is when air conditioners or water heaters fail, but customers, equipment wholesalers, and installers need to be primed and ready to avoid emergency like-for-like replacements.

- Residential DER has high potential for DR benefit and should be prioritized and explored.
- Purchase incentives for Battery Energy Storage Systems (BESS) should be offered to provide DR.
- Pair BESS with significant TOU rates to enable energy arbitrage.
- All residential upgrades must include automated controls to support utility DR calls.
- Explore the costs and benefits of promoting and incentivizing installation of advanced solar inverters, designed to comply with grid codes and standards like IEEE 1547 and UL 1741, enabling them to support the grid by providing functions like voltage regulation and reactive power support.
- Eliminate EE incentives for cooling-only HVAC, instead focusing on efficient heat pumps to better balance seasonal loads, improve system load factors and lower kWh unit costs.

Stakeholder Engagement

- Recommend ongoing engagement of EPE and E3 with stakeholders to ensure full consideration. Recommend meeting every six months.

Eddy Tie

- Continue high-priority detailed investigation of the costs and benefits of upgrading the Eddy County HVDC tie to provide a 200 MW (or more) bidirectional connection.

Large Load Customers

- Require each new data center customer to provide Demand response capacity equal to 20% of their estimated peak system load prior to interconnection. Maintain 20% DR capacity as they grow. Can be DR on their own account or DR purchases elsewhere in the system.
- Special service contracts:
  - recover the permanent transmission cost from the Large Load Customer.
  - Protections for other customer classes: recover costs of both temporary self-power and permanent renewable resources to meet the RPS requirement
  - regulator review and approval of large projects and special service contracts related to these customers.
- Develop and publish EPE's strategy for transmitting power to new Data Centers/Large Customers that interconnect years before long term generation resources are obtained to support them. Include an analysis of the short- and long-term impacts on transmission investment of co-locating data centers with new generation, and co-locating data centers with existing generation. Include impacts on transmission assets beyond immediate interconnection investment both short and long term. Publish by December 2025.

Social Cost of Carbon

- Report emissions for all model alternatives for both peak and average demand load.

Natural Gas

- Takeaways indicate that minor NG price fluctuations do not impact system resource costs. Investigate the cost impact of purchasing Certified NG (certified to be produced downstream to upstream with controlled losses). Claim the Certified NG benefits as a savings for the Social Cost of Carbon.

Emerging Technologies

- Continue to explore emerging tech: small modular nuclear reactors, high-temp geothermal, LDES (ELCC values, costs)

T&D Investments

- Identify the extent of Dynamic Line Rating implementation on EPE's transmission system. Specify lines where it is already installed. List specific short- and medium-term opportunities for further implementation. Publish in the IRP or by December 2025.

- Identify the extent of Advanced Power Flow Control installations on the EPE grid. Specify lines where it is already installed. List specific short- and medium-term implementation opportunities.Publish in the IRP or by December 2025.
- Identify other grid enhancing technologies that should be evaluated for future implementation. List specific short- and medium-term implementation opportunities.

Randy Rankin

- Take advantage of load reduction using DR & DER technologies to reduce the Base Case.

SPP Market Enhancements

- Prioritize regulatory filings and RFP's to determine costs to upgrade the Eddy County HVDC tie to provide 200 MW bidirectional connection. Evaluate the return compared to other.DR and DER alternatives
- Begin negotiations to purchase renewable contracts with the SPP to minimize the Least Cost + REA baseline resources.

C&I Demand Response

- Mimic the 2008 California Technical Assistance/Technical Incentive (TA/TI) program for C&I DR.
  - Keep the program as simple as possible to maximize the fraction of deployment costs resulting in DR (vs. management)
  - The CA TA/TI program incurred low participation with small C&I clients. Potentially consider a ranked $/kW DR with smaller participants receiving a higher $/kW incentive. (potentially divided by rate class).
- Make automated control upgrades mandatory for automatic (pre-negotiated) utility calls for DR.

Residential Demand Side

- All residential upgrades must include automated controls to support utility DR calls
- Pair BESS with significant TOU rates to incentivize BESS with energy arbitrage payback.
- Heat Pumps incentives are not directly DR, but should be investigated for both EE and utility Load Factor improvement. Eliminate EE incentives for cooling-only HVAC..
- Develop agreements with community LMI housing for day-to-day energy savings and utility DR assets.

Cost of Carbon

- Report emissions for all model alternatives for both peak and average demand load.

Natural Gas

- Investigate the cost impact of purchasing Certified NG (certified to be produced downstream to upstream with controlled losses). Claim the Certified NG benefits as a savings for the Social Cost of Carbon.

Emerging Tech

- Issue an RFP just prior to the next IRP cycle to obtain current (at that time) long duration energy storage cost estimates.

Large Load Customers

- Recommend the utility tariff shall recover costs of both temporary self-power and permanent renewable resources to meet the RPS requirement so that other customer classes are not unfavorably impacted.
- In addition, the cost recovery fraction of the renewable resources to meet RPS goals should be accelerated allowing the net-zero generation connection with the larger utility system.
- The tariff should also recover the permanent transmission cost from the Large Load Customer.