2023 NEW MEXICO INTEGRATED RESOURCE PLANNING (“IRP”)

Modeling Scenario Requests

Distributed Energy Resources

"I would be interested in modeling a battery powered virtual power plant program similar to the pilot program by the New Hampshire Electric Cooperative"

- ***Jim DesJardins, REIA***

Existing PRM (15%)	Electrification & Emerging Technologies Load	Base	Base Upgrade Costs ($400/kW)	Long Duration Storage (100 hr)

Quantification:

SPS proposes to include DERs as selectable resources in EnCompass, capable of providing the equivalent of 5% of New Mexico total residential and small C&I sales. SPS will use NREL cost data to estimate to cost of the resources. If EnCompass does not economically select the DERs, SPS will run a case with these resources 'forced' into EnCompass to quantify the cost impact.

Demand Response

"Run a model which allows no cost demand response. This will enable to SPS to back out the value of demand response on its system compared to other resources. The demand response should be available year round, callable once per day, callable hours equal 100, callable at any time of day. This program should be incremental to any DR in the existing forecast.

- Michael Kenney, SWEEP

Existing PRM (15%)	Planning Load (85%)	Base	Base Upgrade Costs ($400/kW)	Long Duration Storage (100 hr)

Quantification:

SPS proposes to include a 200 MW demand response program using the parameters described above (or similar) at no cost. SPS will then provide the PVRR savings associated with the program

Time Of Use Rates

"Model an updated load forecast which reflects residential and small commercial load shift in response to dynamic rate such as time of use. I recommend shifting energy use from SPSs net peak period and into the overnight or midday period."

- Michael Kenney, SWEEP

Existing PRM (15%)	Electrification & Emerging Technologies Load	Base	Base Upgrade Costs ($400/kW)	Existing Technology Only - Wind, Solar, Battery (4hr, 6hr, 8hr)

Quantification:

SPS proposes to shift 5% of New Mexico residential and small C&I sales in the 4 peak hours to off-peak.

Early Compliance

"Please model early achievement of decarbonization goals. This would mean 80% carbon-free resources by 2030 and 95% by 2035 on the pathway to 2040 zero carbon target."

-Michael Keeney, SWEEP

Existing PRM (15%)	Planning Load (85%)	Base	Base Upgrade Costs ($400/kW)	Long Duration Storage (100 hr)

Reciprocating Engines

“Add reciprocating engine as candidate resource. You could assume an 3 engine increment (56 MW) as that's where economies of scale kick in on the balance of plant. I'll provide you in a separate email the cap ex, op ex, and physical parameters you need. I'll also provide "sub-hourly" credits for battery, RICE, and CT, which will be in $/MWh. This should be added as a "negative VOM," and should have the appropriate impact on the capacity factor of the unit. Alternatively I can provide as a fixed $/kw-yr adder. We've calculated these credits in PLEXOS using a SPP node in Carlsbad, NM. As for end state, I can provide a rough capex for a hydrogen conversion in 2044 or whenever you want to do the conversion. I assume you'll have a price forecast for the cost of the hydrogen fuel.”

-David Millar, Wartsila

Increased PRM (18%/20%)	Planning Load (85%)	Base	Base Upgrade Costs ($400/kW)	Hydrogen Conversion

ExxonMobil

"Demand side:
- Include the load demand information out to 2040 for SPS territory provided by the Permian electrification study, added to existing assumptions on other customer growth
- Present the load estimate data out to 2040 broken out by general customer groups, not necessarily rate classes, e.g. Large industry customers, residential, transport electrification, data centers, crypto mining.

Emissions:
- There are two potential emissions related models constraints we would like to have considered:

1. A model that demonstrates the pathway to 84% renewable deployment for SPS grid (NM & TX) by 2030 per RBC June 7, 2023 conference for the electrification increased load model… external customers are basing their own future emission reduction targets and pathways in part on estimating the future carbon intensity of the gird. Understanding the pathway and likelihood of 84% renewable by 2030 for the SPS grid is important for customers with emissions targets. July 6 material showed 88% renewable by 2030, but not for the increased load anticipated with Permian O&G production electrification and other potential load growth." ***(Continued on next pg.)***

ExxonMobil

2. *A model that embraces industry leading hydrogen deployment and CCS deployment*

a. *All new source facilities (including TX given recent 88th session legislation incentives) having the ability to co-fire with 50% low-GHG hydrogen by volume by 2033 (technically feasible today and 2033 incentivizes hydrogen producers with certainty due to current IRA expiring in 2033). The source of hydrogen modelled should be lowest cost and low carbon, based on the known practical cost assumptions for hydrogen generation, transportation and turbine/facility upgrades, and not preferential to any specific color (i.e. green, pink, blue).*

b. *Existing natural gas base generation facilities blending 30% hydrogen by 2033 or existing natural gas facilities considered base generation retro-fitted with CCS by 2033 based on optimized cost.*

-James Hall, ExxonMobil

Existing PRM (15%)	Electrification & Emerging Technologies	Base	Base Upgrade Costs	Hydrogen Conversion

Sierra Club

Existing PRM (15%)	Financial Load (50%)	Low	Base Upgrade Costs ($400/kW)	Existing Technology Only - Wind, Solar, Battery (4hr, 6hr, 8hr)

1. *SPS should conduct a sensitivity modeling the Impact of "high" renewable penetration under the Inflation Reduction Act on SPP import energy prices.*

2. *SPS should run sensitivities for compliance with EPA's Section 111(b) and 111(d) regulations for new and existing EGUs with the following considerations:*
    a. *Tolk: Because Tolk plans to retire in 2028, no new controls would be required but the model should limit those units to their current emissions rate through 2028.*
    b. *Harrington: Because Harrington plans to convert to gas by 2025, the units should be modeled to include 111(b) limits for existing gas plants.*
    c. *Jones: SPS should explain whether Jones will continue to operate past 2032, and if so, whether the facility would exceed the 300 MW threshold for existing units under 111(b).*

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d. *For any new gas plants added to the system: New resources and projects should be set up in EnCompass to represent the 3 categories of new gas plants that can be built. All new gas plants (regardless of capacity) will need to follow one of these pathways to be compliant with 111(d). The model should not be able to build any gas plants that do not follow one of these pathways.*

- *i. Peaking plants - Annual capacity factor set to a maximum of 20%.*
- *ii. Intermediate plants - Annual capacity factor set to a maximum of 50%. These plants must start burning fuel that is 30% hydrogen by volume in 2032.*
- *iii. Baseload plants - No capacity factor cap. Baseload plants can either follow the carbon capture and sequestration (CCS) pathway or the hydrogen pathway.*
  - *a. CCS resource requirements - Retrofit cost of CCS incurred in 2035. Increased FOM and VOM associated with CCS incurred in 203 onwards. Account for parasitic load of CCS.*
  - *b. Hydrogen pathway - These plants must burn fuel that is 30% hydrogen by volume in 2032 and fuel that is 96% hydrogen by volume in 2038.*
  - *c. General considerations for modeling 111(b) and 111(d)*

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Optimization period:
When modeling retrofit costs in future years, the runs should be set to full optimization so that the model can see these future costs. If you need to run the model with a shorter optimization period for run-time constraints, the future retrofit costs should be levelized so that the future costs are considered during the capacity expansion decision.

Modeling hydrogen:
Model hydrogen endogenously or exogenously (i.e., are you planning on producing the hydrogen yourself or are you assuming a hydrogen economy will exist by the time you need it.). If endogenous, set up electrolyzer resources in EnCompass and connect them to renewable resource generation outputs using Flow Gate constraints. The Inflation Reduction Act's hydrogen PTC can currently be modeled using the variable cost of operating an electrolyzer. If exogenous, EPA assumed a hydrogen price of $1/kg (around $8/MMBtu) in its Regulatory Impact Analysis. Model low and high sensitivities for the price of hydrogen.

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Modeling CCS:
Include capital costs for retrofit, incremental fixed O&M and variable O&M. Include parasitic load assumptions (EPA assumes approximately 11% and as a result, FOM, heat rate, and VOM need to be scaled). Include IRA tax credits.

-Joshua Smith, Sierra Club

QUESTIONS ?