Maryland Power Plant Research Program

Meeting Minutes of the 100 Percent Study Working Group

February 18, 2022

Presentation Recording

Attendees

Status of Study

- There was a delay in running VCE's model due to administrative issues and for incorporating Illinois' new energy law that was enacted in September 2021.
- Fred Kelly will give stakeholders until March 4th to provide comments on the presentation and then will post the comments on the PPRP webpage. These comments will include those provided before the presentation by Alex Pavlak and Julian Silk.
- Once PPRP, Exeter, and VCE have reviewed and responded to the comments and made any necessary changes to the model, the team will do the three initial model runs:
    - Base case (economic run with current Maryland RPS)
    - Two preliminary scenarios
        - 100% RPS
        - 100% clean energy (modeled after proposed, but not enacted, Clean and Renewable Energy Standard, or CARES)

Approximations and Model Run Time

- There have been several changes to inputs and assumptions since the August 2021 Working Group meeting.
- PPRP encourages feedback on the changes but wants to express that there is a tradeoff between developing a precise model of the electric power industry and the amount of time that is needed to run VCE's model. Therefore, assumptions were made to adequately capture as much of the detail of the electric power industry as possible, while also maintaining a manageable model processing time.

Transmission Modeling

- VCE's model builds out transmission and models transmission flows to as low as a nodal resolution.
- There are tradeoffs with this level of detail → the time needed to run the model. Therefore, VCE is modeling transmission buildout at county-level resolution and transmission flow at state-level resolution.
    - Except for Maryland, where VCE is modeling transmission flows at county-level resolution.
- VCE's model had originally assumed only two approaches to modeling new transmission capacity:
    - All transmission expansion as new builds with double-circuited lines, with substations every 100 miles.

    - Retired plants open new transmission capacity on existing lines at the node of the retired plant.
- For the current modeling, VCE added ability to upgrade existing lines, which is important for PJM given the age of PJM's transmission system and the location of some lines in urban areas, making new line construction difficult. VCE will model the opportunity to move up one voltage class (e.g., from 138 kV to 230 kV) for existing lines using costs numbers from PJM's 2021 Offshore Wind Study rebuild option.
    - These costs will provide additional level of detail that better reflects the PJM system without sacrificing resolution.
    - The model will only include only cost estimates for transmission line upgrades and not new transformers because the model limits upgrades to moving up one voltage class.

Transmission Modeling Questions:

1. Do the transmission upgrades in the model represent upgrades needed for new generation plants construction, upgrades for reliability purposes, or supplemental transmission projects? Or all three?

   The model upgrades are for transmission required to interconnect new build generation or more efficiently used generation. The model does include transmission capacity as part of planning reserve margins, although VCE has found that it plays a smaller role than generation.

2. Does the model consider any new transmission lines or is it just the changes in voltage?

   Yes, the model does include an option for new transmission lines. First, the model considers transmission line upgrades and there is an upper limit on how big the upgrade is (i.e., one voltage class). Once the line hits that ceiling, any additional transmission capacity will come from building new transmission lines.

3. For the 100% scenarios, will the study include how much more transmission is needed, both from upgrades and new transmission lines?

   Yes, the study will describe how much transmission (MW capacity and MW lines) was added at a county-level resolution.

4. There are parts of the Build Back Better Bill that would reduce costs for transmission build out, if passed. Is that easy to factor into the model?

   Yes, however, if the model runs have already begun, it would have to be a separate sensitivity analysis.

Maryland Greenhouse Gas Emissions Reduction Act

- In 2021, the Maryland Department of Environment's (MDE) released a report call for a 48.7% reduction in statewide GHG emissions by 2030.

- VCE and Exeter view this as a goal, not a requirement, and are not including it in the initial three scenario runs. However, it is possible that the GGRA goal would be met by either or both of the 100% RPS and 100% clean energy scenarios.
    - A similar standard applies to goals in other states (e.g., Illinois) that also have GHG reduction goals.
- The model will almost certainly have a sensitivity case on climate change. Some possibilities include 50% reduction by 2030 and Net zero by 2050.
- There is legislation pending before the Maryland General Assembly and the sensitivity analysis will reflect whatever legislation is passed.
    - The working group will be allowed to comment on the proposed sensitivity analysis scenarios after the legislative session has wrapped.

GGRA Comments:

- Mark Stewart: The Maryland state agencies see the GGRA as being pretty firm. There should be more clarity as the Maryland General Assembly wraps up about what the 2030 target for GHG reductions should be and the sensitivity analysis should include that.
- Michael Powell: The other parts of the GGRA result in changes to what we are proposing for heating building and electric car charging stations. The sensitivity analysis should include this as well as the resulting shift of peaks.

GGRA Questions:

1. Would the net zero sensitivity analysis remove all Tier 1 renewable technologies that are not zero emissions?

   Unless they have a carve out, we do not have to remove them because the model, if required to simulate zero emissions, will pick only technologies that don't have emissions.

   Mark Stewart: The net zero legislation that is being considered by the general assembly does not apply only to the electricity sector. However, it is a safe assumption that in order for MD to achieve net zero goals, then the electricity sector would have to be net zero also.

Illinois Clean Energy Jobs Act

- There were some substantial changes to Illinois energy laws from the Illinois Clean Energy Jobs Act (CEJA). The model will include all of Illinois, not just the part that is in PJM because otherwise, all the renewables in the state would be packed into the ComEd territory.
    - We are not including 100% clean energy goal because it is beyond the 2040 target that is part of this study.
    - We assume that the Braidwood, Byron, and Dresden nuclear power plants do not retire while receiving financial support.
    - We assume actual energy efficiency requirement is net of "deemed annual savings" and "annual energy efficiency" targets (annual minus deemed).
- The Illinois CEJA has several provisions for fossil-fueled plants (e.g., coal, oil, natural gas) to be either retired or at zero emissions by certain dates, dependent on ownership, level of air emissions, and location to EJ communities.

- PJM is talking to Illinois EPA about how they can run the grid with these restrictions and are working on operating guidelines. There are currently no specifics regarding this, so it will not be included in the model.

Updates to Technology Types in Model

Geothermal Heating and Cooling

- Added geothermal heat pump (GHP) technology because it has a carve-out in the Maryland RPS and set a baseline for current capacity installed by using data from PJM-GATS. Therefore, there will be some minimum GHP capacity that goes into all scenarios modeled.
- GHP is more expensive than traditional heaters and A/C but is also more efficient. The model will work to balance these costs and benefits.
- The model won't allow utility-scale geothermal to be built going forward.
- Maryland has colder winters and warmer summers, therefore there are large seasonal swings as the GHP is used more in the winter. The implication of this, is that increased use of GHP in Maryland could increase loads in the winter.

GHP Questions:

1. There is a good deal of cost variation for GHP due to geography (e.g., sandy vs rock-heavy soils). Is this a factor in the model's cost estimations?

   The model will use an average of several cost sources to capture that variability.

2. With the performance improvements of air-source heat pumps and the cost of effectiveness when compared to GHP, in terms of installed costs, there may not be as much potential for GHP in Maryland. Would this factor into the model?

   Air-source heat pumps do not work on very cold days. You are forced to use strip heating, which would increase peak capacity. The geothermal heat pump is a better technology when you consider its impact on the power grid because it works during very cold days. The new cold climate air-source heat pumps can go down to -15 degrees Fahrenheit, with coefficient of performance (COP) ratings of three or greater, but GHP will have more stable COP characteristics and show less radiation. The model is also not considering air-source heat pumps because it is not looking at economy-wide electrification.

3. What is the cost difference between GHP and traditional heating and cooling?

   GHP is $2,500/kW

   HVAC is $800/kW

   Assisted heaters $150/kW

   There is a significant cost delta between HVAC + assisted heaters, but there are substantial advantages in the load. The model will be trying to figure out whether the sector should build

more generation to deal with the existing load from HVAC + assisted heaters or should the sector transition to GHP, which will reduce the load?

Combined Heat and Power

- Under a proposed Maryland CARES, Combined Heat and Power (CHP) plants must meet certain efficiency requirements. Unlike GHP there is no carve out, but the model can choose CHP if it is viable.
- Because other CHP technologies saw only a small efficiency increase at high cost, we plan to only model an average of gas turbines and reciprocating engines as CHP units, because they are the most representative of what is currently out there.
    - Reciprocating engines are currently most installed by unit count and gas turbines are most installed by capacity.
    - Fuel cell levels have similar efficiency levels, but the capital costs are much higher.
- None of the CHP had efficiency levels to be eligible for a full clean energy resource credit under CARES Act and will receive only partial credit.

Carbon Capture and Storage – Natural Gas

- By default, the model can choose to build a new natural gas unit and natural gas + CCS. The model has been updated to be able choose to retrofit existing natural gas plants with CCS as an option.
- Assume 95% efficiency for new natural gas + CCS and 90% for a CCS retrofit to meet the requirements of CARES.
    - There are no 100% efficient units.

CCS – Natural Gas Comments:

The model should take into consideration limits to the kind of CCS that can be included in the CARES.

CCS – Natural Gas Questions:

1. What type of technology for CCS?

   The Natural Energy Technology Laboratory (NETL) study has three CCS technologies and the costs are the average of those three.

Carbon Capture and Storage – Biomass

- By default, the model can choose to build a new biomass unit. The model has been updated to include a new biomass unit with CCS or retrofit a current biomass unit with CCS. This technology is allowed double-credit for CARES.
- Assume 90% efficiency for new biomass + CCS and 90% for a CCS retrofit to meet the requirements of CARES.
    - There are no 100% efficient units.

CCS – Biomass Questions:

1. Does the model drive the 100% RPS and 100% clean energy to zero emissions so that Bioenergy with Carbon Capture and Storage (BECCS) would come in as an end piece that would eat up residual emissions that might exist from natural gas CCS and CHP?

   Yes. In the three model runs, there are no zero emission constraints because they are all goals, so they have been left out. The model, in these cases, will be built upon RPS and Clean Energy requirements so there will be emissions remaining. For any type of CCS to qualify, only the clean portion qualifies. Ultimately, the model has to choose how it will meet the RPS and Clean Energy requirements. The final output of the model will report residual emissions from the scenarios.

Biomass and Hybrid Resources

- By default, biomass can be selected as an option in the model. The sub technologies of biomass mass (e.g., waste-to-energy, landfill methane, wood waste, etc.) are all included under one block to minimize run time of the model.
- This affects the calculation of RECs. To handles this:
  - The percentage of biomass generation in this block that qualified for RECs in 2020 will be fixed to 2020 percentage values.
  - RECs will change based on how much biomass the model decides to build, retire, or any other changes in capacity or usage.
  - Black liquor will not be eligible for RECs after 2020.
- Similarly, hybrid resources (e.g., solar and storage) are not modeled explicitly but does co-locate and optimize the resources on any given node.

Small Modular Reactor Costs

- The model does allow for the advancement of some nuclear technologies, including SMR technology but only for the Clean Energy scenario run.
- Capital costs have been updated using a 2019 study "Economic viability of light water small modular nuclear reactors: General methodology and vendor data. Renewable and Sustainable Energy Reviews"

Questions:

1. How do you handle 2020 costs for CCS, biomass, and SSR inflating and deflating over time as costs decrease or increase overtime as technology evolves? Will the SMR be handled as first of a kind (FOAK) technology?

   Everything that goes into the model is converted into 2020 real dollars and everything that comes out of the model is 2020 real dollars.

   We are not going to assume any cost decrease for SMR since it is so new in the market. This is all theoretical because one has not been built yet. The cost and heat rate numbers in the model are indicative of an nth of a kind (NOAK) technology.

Discount Rate

- Previous plan was to use the NREL Annual Technology Baseline (ATB) ~2-4% discount rate depending on technology
- Since then, there has been a lot of discussion about what the appropriate discount rate should be given inflationary pressures. We are proposing to raise the discount rate to 5.87%, which falls in the middle of a range of rates.

Note: There was confusion among stakeholders about the use of the term "Discount Rate". In the NREL ATB, the term Discount Rate is used interchangeable with weight cost of capital (WACC). Going forward, Exeter and VCE plan to use WACC. For full discussion, please see presentation recording.

Questions about Discount Rate:

1. If the analysis is in 2020 real dollars, why does inflation have an impact?

   When you are calculating WACC for financing projects you must account for inflation. There is an inflation component related to interest rates. All of the analysis is in 2020 real dollars, but the WACC takes into account what the inflation is going to be.

2. Does the discount rate also go into the carrying costs for capital? EX: When you build an SMR project, you are paying a portion each year. How long is amortization for those projects?

   It differs for each technology, for SMR, the life of the reactor is estimated to be 60 years. This is based on a typical lifetime for a typical nuclear plant.

3. Is the length of time to amortize for a natural gas CCS retrofit based on the retrofit or the plant itself?

   For, retrofit the capital costs will be amortized over the remaining book life of the plant. Natural gas plants are amortized over 30 years. So, whatever is left of the 30 years when you retrofit the plant is what the retrofit will be amortized over.

Offshore Wind Build-Out in Maryland

- Updating assumptions about what offshore wind resources are coming online and when, based on the December 2021 PSC order that:
  - Approved the issuance of Offshore RECs (ORECs) to US Wind and Skipjack for two offshore wind projects totaling 1,654 MW both projects.
  - Included new timetable for projects.
- Based on our understanding of expected online dates, we are assuming the following:
  - The first US Wind project (248 MW) comes online by 2025.
  - The three remaining projects (1,774 MW) come online by 2027.

Offshore Wind Questions:

1. Offshore wind developers have been historically ambitious in terms of projected timing. What will happen if developers are unable to meet this timeline?

   The model is making a hard assumption that they are coming online on these dates.

General Comments:

1. Alex Pavlak: This study is using a bottom-up approach for the model.
    a. This will give very different results from a top-down approach which would result in:
        i. Generation with high peak load availability.
        ii. Minimum transmission.
        iii. Low sensitivity to EMP solar storms and single points of failure.
        iv. Largely distributed generators designed for high reliability and a low mix of intermittent generators.
    b. With the bottom-up approach you are starting with existing grid and locking into a lot of attention to transmission and transporting electric power from Midwest to East.
    c. Concerned that the two approaches will never converge.
    d. However, the bottom-up approach is what is required by legislative requirement, which asks if Maryland can get to RPS and clean energy goals with current infrastructure and grid.
    e. Is the legislature asking the right question?

Amended Project Schedule

- March/April/May: Run model/analyze results; vet results with PPRP and working group, re-run model as needed
- June: Recommend sensitivity scenarios and vet with PPRP and working group, begin sensitivity model runs
- September: Finish sensitivity cases, analyze and share results with PPRP and working group
- December 2022/January 2023: Finish modeling, use model output for input output modeling
- March/April 2023: Finish input-output modeling, begin drafting report
- Fall 2023: Finalize and issue report
- January 1, 2024: Final deadline for providing the report to the governor per CEJA