ENVIRONMENTAL MANAGEMENT COMMISSION
AIR QUALITY COMMITTEE MEETING SUMMARY
March 10, 2021
Virtual Public Meeting
11:15 – 12:25 A.M.

MEETING BRIEF

During the March 10, 2021 meeting, the Air Quality Committee (AQC) of the Environmental Management Commission (EMC) heard:

- Informational Item: North Carolina Power Sector Carbon Policies, An Analysis of North Carolina Clean Energy Plan Recommendation A1

AQC MEMBERS IN ATTENDANCE	
Ms. Shannon M. Arata, AQC Chair	Ms. Marion Deerhake
Mr. Charles S. Carter, AQC Vice-Chair	Ms. Maggie Monast
Ms. Donna Davis	Mr. John McAdams
Ms. Suzanne Lazorick	

OTHERS IN ATTENDANCE	
Dr. Stan Meiburg, EMC Chairman	Mr. Phillip Reynolds, EMC Counsel
Mr. David Anderson, EMC	Mr. Mike Abraczinskas, DAQ Director
Mr. Donald van der Vaart, EMC	Mr. Michael Pjetraj, DAQ Deputy Director
Ms. Pat Harris	DEQ Staff
	Members of the public

PRELIMINARY MATTERS

Agenda Item I-1, Call to Order and the State Government Ethics Act, N.C.G.S. §138A-15
AQC Chair Arata called the meeting to order and inquired, per General Statute §138A-15, as to whether any member knows of any known conflict of interest or appearance of conflict with respect to matters before the EMC's AQC. Commissioner Monast indicated that she consulted with Counsel Reynolds regarding relation to one of the presenters, but Counsel Reynolds had determined there was no conflict

because no action was being taken on this information item and the report does not make any recommendations of the EMC.

Agenda Item I-2, Review and Approval of the November 18, 2020 Meeting Minutes
Chair Arata requested approval of November 18, 2020 Meeting Minutes. Commissioner Deerhake made the motion and Commissioner Monast seconded the motion. The minutes were approved without a discussion.

RULEMAKING CONCEPTS
None.

ACTION ITEMS
None.

EMC AGENDA ITEMS
None.

INFORMATIONAL ITEMS

Agenda Item V-1, North Carolina Power Sector Carbon Policies, An Analysis of North Carolina Clean Energy Plan Recommendation A-1.

Chair Arata introduced the presenters, Ms. Kate Konschnik and Mr. Jonas Monast**,** and requested the members of the Committee to hold questions for the end of the presentation.

Ms. Kate Konschnik, Climate and Energy Program Director, Nicholas Institute for Environmental Policy Solutions, Duke University, and **Mr. Jonas Monast**, Director of the Center on Climate, Energy, Environment and Economics (CE3), UNC School of Law, did a presentation about the report on carbon reduction policies for the North Carolina power sector conducted by Duke University's Nicholas Institute for Environmental Policy Solutions and the University of North Carolina's Center for Climate, Energy, Environment, and Economics. The presentation was focused on policies identified in Recommendation A-1 of the North Carolina Clean Energy Plan (CEP). The report reflected extensive modeling, policy and economic analysis, and a year of work with stakeholders representing diverse constituencies in North Carolina. The report also evaluated design options and the associated tradeoffs for policymakers but did not make specific recommendations on the path forward.

Presentation

The PowerPoint Presentation information notes were presented and commented by both presenters.

Mr. Jonas Monast started the presentation indicating that the CEP Recommendation A-1 Report was already released to the public domain. The report was authored by researchers at UNC Center and Duke Nicholas Institute and reflects broad stakeholder engagement that took place during 2020, which informed the policy scenarios that were analyzed and helped to inform the data and modeling assumptions used that underlay the analysis. Two caveats: (1) the report does not make recommendations or tell the State what to do; it seeks to inform the State of options to cut greenhouse gas emissions and achieve the CEP goals, particularly, Recommendation A-1, and (2) the report is not a prediction of the future; numbers should be viewed for directional purposes only. The goal is to help stakeholders and policy makers evaluate the options for reducing greenhouse gases from the electric power sector and consider the trade-offs associated with each of the policy options, but not to predict what will happen in these policies. Because it relies on the best available information to date and assumptions about what may happen in the future as part of the stakeholder engagement process, the further that we go out into the future, the less reliable and more uncertain it will be. Because the CEP identifies goals for 2030 and 2050, those dates were used for the analysis of this report.

Ms. Konschnik presented the Clean Energy Plan Goals.

EO-80 set economy-wide carbon pollution reduction targets and directed DEQ to run a stakeholder process that culminated in the CEP, which established additional goals for cutting carbon pollution from the power sector. Three important points were explained regarding these: the first point notes that these reflect deeper reductions than the economy-wide goals set by the Governor in EO-80 because there are more readily-available technologies in the sector to begin de-carbonizing today, relative to other sectors, such as different industrial sources. In addition, EO-80 contemplated the electrification of other sectors, including transportation, since cleaning up the grid enables electrification without additional emissions. The second point notes that these emissions goals do not just relate to in-state generation, but also the emissions associated with any electricity imported to North Carolina for use. This can require tricky accounting compared to just reading CEMS of smokestacks of our own power plants. Including emissions associated with imports is also more challenging because state policies could only indirectly affect how generators in other states choose to generate electricity. The third point is regarding the carbon neutrality goal. This does not necessarily mean the power sector will emit nothing in 2050, but that anything emitted must be offset elsewhere in the economy. For this reason, when modeling the different policies, the model was generally told to solve for 95% of reduction in pollution from 2005 levels rather than 100%, which helped with grid reliability, among other things. The report authors did not dig into how to reach that last 5% of emissions.

Mr. Monast talked about the CEP Recommendation A-1, A-1 Process, Involved Sectors and A-1 Report Overview.

CEP Recommendation A-1. The Clean Energy Plan Recommendation A-1 laid out four broad categories of options for GHG emissions reductions from the power sector: (1) accelerated coal retirements, (2) market-based carbon reduction programs, (3) clean energy polices, such as an updated Renewable Energy Portfolio Standards, Clean Energy Standards, and Energy Efficiency Standards, and (4) combinations of these strategies. The CEP called the University to conduct a report and make recommendations. Through the engagement of stakeholders, they decided not to make recommendations and rather focus on analysis because there are so many ways to achieve the goals of the CEP and wanted to make sure to lay out the different strategies and trade-offs rather than trying to focus on achieving agreement from the stakeholders about a particular plan.

A1 Process. The A1 process started before the pandemic with a few in-person meetings, including broad stakeholder meetings that started with those that participated in the CEP process itself, supplemented with invitations to other interest groups. To narrow down the broad list of options and ensure representation of various perspectives, recognizing that detailed communication with over 90 participants was not possible, a policy working group and a technical working group were formed. This intensive stakeholder process informed choices that were made for the policy options that were analyzed.

Involved Sectors. The categories of sectors and perspectives involved in the process were: (1) electric utilities (IOUS, coops), (2) State agencies, (3) renewable energy companies, (4) Universities, (5) industrial customers, (6) low-income advocates, and (7) environmental groups and justice advocates.

A1 Report Overview. The report overview details the choices that were made and how the broad goals from the CEP Recommendation A-1 were translated into the analysis in the report. The first option is accelerated coal retirements, which contains a number of options: all or some coal retires on a particular date, or some coal remains operating on a seasonal or as-needed basis. Multiple scenarios are included under accelerated coal retirements to reflect those different approaches. The second option is carbon "adders" on new construction or generation, which is a shadow price on carbon included in the analysis for what a utility builds or when the utility is deciding what generation options to dispatch, in the same way that they consider fuel and other costs. The third option is the declining carbon budget, which was modeled as North Carolina participating in the Regional Greenhouse Gas Initiative (RGGI). This is a carbon market in operation in the mid-Atlantic and northeastern states and which Virginia opted to join last year. There are a number of options for how the participation in RGGI would work in North Carolina, particularly, whether allowances are auctioned or freely allocated. In the carbon market, allowances are tradable and exchangeable but at the end the compliance period, if you are converted by the program (in this case, electricity generation using fossil fuel or emitting CO_2), you would need to have an allowance representing every ton of CO_2 emitted during the compliance period. The last option, Clean Energy Standards (CES), are similar to the renewable energy portfolio standard that we have in North Carolina right now, except that compliance is based on the definition of clean energy instead of renewable energy. There are many options for designing and implementing clean energy standards. The stakeholder group recommended this analysis focus on a clean energy definition of zero-emitting, zero carbon generation, and generation located within the state, which changes the generation mix and costs. The CES analysis was supplemented with scenarios that considered offshore wind and energy efficiency for compliance.

Ms. Konschnik talked about the RGGI Options and the Policy Dynamics.

RGGI Options. They ran variations of the policies discussed by Mr. Monast. Usually, that meant different levels of ambitions, for example, whether some or all the coal is retired by 2030, or whether a carbon adder is built into new construction decisions starting at $6, $13, or $42. There were some additional considerations for the carbon market pathway when defining what to model. The group decided to look at two levels of ambitions for 2030. Another factor was how the allowances to pollute would be distributed, and if they were sold to regulated entities, how that money may be reinvested. North Carolina can distribute the allowances for free and the Utilities Commission would probably treat those allowances as having some value and direct the IOU to pass those savings onto the customers. By contrast, the State could auction those allowances like the other 11 states in the RGGI program, which leaves the decision of what to do with the revenues. They modeled a scenario where those auctions revenues went back to general treasury for whatever priorities the state may have, and therefore, were not recycled back into the electric sector. They also tested after setting aside 5% for administrative costs, different types of investment by putting all the money into energy efficiency investment, or all into residential bill assistance to see the cost on emissions and change in the makeup of the grid. In fact, the states that do auction allowances do not put all dollars into one project or another, instead having a portfolio approach of investing in a combination of storm recovery efforts, coastline protection, energy efficiency, and bill assistance.

Policy Dynamics. The analysis tested different push and pull mechanisms to see what was more effective and most cost-effective at reducing pollution on the grid. Some policies put more downward pressure on coal units or generally on anything that emits carbon dioxide, such as the carbon adders or RGGI program. The outcomes of the "push" policies can be compared to see if it will be better to target the most carbon-intensive resources, such as coal units, or discourage emissions generally, and then let the market figure it out. They analyzed whether the "push" policies are efficiently indirectly bringing clean energy online. Meanwhile there are other policies that require construction of clean energy resources, by pulling new resources onto the grid. Those could be technology-neutral standards or specifically include offshore or onshore wind energy, storage, or other lifted resources. Then what happens if you deploy "push and pull" policies? The analysis also looked policy combinations to see how that changed results of cost, emissions, or make up of the grid. They found that generally those push policies were not efficient at bringing new clean resources onto the grid, instead relying on more electricity imports to make up the difference. Likewise, the "pull" policies were not as efficient at pushing the more carbon-intensive units offline, but combining them created advantages. It was important to understand those big dynamics and include them in the report in order to inform decisions about which levers to pull.

Mr. Monast talked about the Bases for Comparison, the A1 Core Values, the A1 Report Caveats, and the A1 Report Take-Aways.

Bases for Comparison. It was reiterated that readers of the report should not rely on the numbers as absolute predictions of the future, but rather the bases for comparison. There are lot of different metrics for comparing the impacts of policies, such as: (1) CO_2 emissions for 2030 and 2023-2050 timeframe, (2) in-state NOx and SOx power sector emissions, (3) imported CO_2 emissions, (4) cost (net present value in total costs over time and $/ton reduced), (5) NC generation and capacity mix over time, and (6) for a subset of the policies, rate and bill changes, and how they translate to different customer classes, as well as job and economic impacts.

A1 Core Values. The CEP also lays out some core values, some of which can be directly addressed by specific numbers from the models. Two of the core values that cannot be addressed by the models are affordability and equity. The stakeholder groups discussed the meaning of these to the different members and metrics for evaluating affordability and equity impacts, as well as policy options for addressing affordability and equity concerns. For example, one way of thinking about affordability is energy burden. Some electricity customers in North Carolina are having hard time paying their bills today, and any increase at all could make it unaffordable for them. The industrial affordability perspective had less to do with the specific bill impacts, and more with how the electricity rates in North Carolina for industrial customers compare to those for industrial customers in other states in our region. Equity can mean access to clean energy, looking at the impacts on the communities bearing the burden of electricity generation today and going forward, and also recognizing that in some communities in North Carolina, regardless a policy, where coal plants are shutting down, a lot of jobs will be lost, which is an equity concern that should play a role in the clean energy policy discussions.

A1 Report Caveats. (1) Duke Energy's IRP came out in the middle of this stakeholder process. There are other ongoing modeling analyses that are not part of this process, which the speakers tried to be aware of to the extent that the information came out, and incorporate into discussions and the analysis. The modeling did not attempt to duplicate Duke Energy's system, and it is not going to look like the IRP results that Duke Energy presents. There were different viewpoints within the stakeholders about the cost trajectory and technology improvement for battery storage or renewable energy, for example. Where there were disagreements or choices of what data to use, they deliberately did not choose the more optimistic views and instead chose a reasonable assumption of data, but also ran different sensitivities in case they did not choose data that reflected the most likely scenario.

A1 Report Take-Aways. It was noted that everybody recognizes that things are going to change; if this analysis had been done 10 years ago, it would have been wrong about where the electricity system would be today. The purpose of the report and analysis was to allow the comparison of different pathways using similar set of data and modeling tools to evaluate this broad range of changes. Broadly, the main take-away is that the electricity system in the state is poised for, and already undergoing, transition. Coal is coming offline, renewable energy is being built, battery storage is starting to appear within our energy mix, and the system, as result, is highly responsive to modest changes in cost for different resources, as seen in the modeling with slight changes in projections of natural gases prices having a large impact on the energy mix. Even modest policies can make big differences. There are number of policies that are cost-effective and achieve the CEP goals (e.g., coal retirements, RGGI < 1% system cost increases).

Ms. Konschnik talked about the A1 Report Take-Aways, the Baseline CO_2 Emissions, the NC in-state Emissions from Generators, the NC Total Emission from Generation (adjusted for imported electricity), Total Emissions Reductions in 2030 (% change from 2005), and the Policy Cost in Net Present Value.

A1 Report Take-Aways. The defined policies were run through two capacity expansion planning models: (1) the IPM model that ICF uses, and (2) the in-house Nicholas Institute model called DIEM. IPM was used because it is relied on by utilities, regulators, and environmental organizations and is a familiar tool in this arena. However, DIEM was also used because this in-house model provides flexibility to do additional analysis. A lot of the policy variations and sensitivities in the report, such as gas and renewable price assumptions and payback periods for new renewable construction, were all done in DIEM. The models did end up with directionally similar results, ranking the policy options in similar order by cost or emissions reductions, but did have some divergence as well, despite coordinating on the assumptions. There were similar assumptions going into both models, but the inherent structures of the models resulted in some differences, as described in the report, which may help to show different ways of solving the problem and the inherent uncertainties. Revisiting the 2030 CEP target, 70% below 2005 levels by 2030, the back of the envelope, business-as-usual, assumption during the CEP discussion was that we would achieve about 50% reduction if we did nothing. Already, that has become more favorable using the two models; IPM showed 53% reduction by 2030 from business-as-usual levels and DIEM showed about 60% reduction, and yet not enough to achieve the CEP target. The policies that actually achieve the 2030 target, as defined, in at least one of the power sector models, were displayed. Coal retirements also got really close in both models. Some of the push policies, such as coal retirements and RGGI, achieved much deeper in-state reductions by 2030 but were making up a little bit of the difference with imports that have some fossil attached to them, which moved them back up. The first item, carbon adder on generation, was only run in DIEM, which already had a deeper baseline because it was seeing more renewables entering the mix and so by proxy RGGI acts somewhat like a carbon adder on generation. RGGI was only run in the IPM model because that is the model that is always used for the states that participate in that program, so there is some uncertainty as to whether RGGI would also achieve the target. It was noted that, since a CES seems to achieve the CEP goal by 2030, one might ask why the analysis bothers to look at CES combination policies. Firstly, it was found that the CES achieved the 2030 target in only one of the models. More importantly, the CES, by itself, is slow to move fossil offline and in fact can continue to coexist with fossil at higher levels than some other policies going into the future. Looking ahead at the long-term trajectory and meeting the carbon neutral mid-century target, it looks important to pair the clean energy policies with a “push” policy to help move fossil offline.

Baseline CO_2 Emissions. The report breaks out in-state emissions versus in-state plus import adjustments, to include emissions associated with any electricity coming over the border because that was how DEQ set the targets in the CEP. All power coming from across state lines that we use had to be included. This can be confusing for conversations with various stakeholders because Duke Energy Progress and Duke Energy Carolinas, for instance, run service territories that cross state lines, so when they are bringing over electricity from a South Carolina plant to meet North Carolina load, that is not necessary an import for them because it is within their system. However, when we think about air rules or clean energy standards that apply to the generators in-state, that becomes more “within the state borders”, and it becomes important to keep straight what “import” means. The differences between IPM model and the DIEM model baselines were displayed. DIEM under business-as-usual had deeper reductions, selecting more renewable resources to meet or replace retiring coal than IPM. NREL was also displayed because NREL has been doing some work in the DOE labs with Duke Energy looking at decarbonization scenarios. They worked closely to keep informed on what NREL is doing in their analysis. NREL used a very different natural gas projection initially than Duke does in their IRPs, while this analysis kept close to Duke's IRPs for natural gas projections. As a result, the NREL baseline assumes much higher gas, so they are not building or using gas as much, instead turning up the coal plants that we have now and running them in the late 2020s, causing the difference seen. The NREL baseline comes down as some of the coal is retired and their gas prices dropped, where it becomes more in-line with the other baselines.

NC In-State Emissions from Generators. Those differences between IPM and DIEM baseline carry through to the policies. A few of the policies were shown, highlighting that coal was retiring faster in IPM than DIEM under a business-as-usual due to pure economics, and yet for the coal that remains, IPM ran a lot harder; whereas the in-house DIEM model was selecting more renewables and using coal more in a reserve capacity. This is the uncertainty into the future: as some coal is knocked offline due to economics, how do we use the remaining coal? This carries through to the policy analysis: the DIEM model tended to show lower emissions because it started from a lower baseline. RGGI was not modeled in DIEM because IPM is the model used by RGGI, Inc and the participating states; therefore, only one line is shown for RGGI between the two graphs. We are seeing that a lot of coal in NC system is barely economic, so the addition of really modest prices at $4-$5 per ton allowance price for RGGI and a $6 per ton carbon adder on generation decisions are enough to push a lot of coal offline, causing some steep initial declines.

NC Total Emission from Generation (Adjusted for imported electricity). Another slide was shown with the results for the same standard policies as the previous slide, but now also considering those emissions associated with electricity imports since the CEP targets include these imports. Note the differences between policies in IPM shrink; before, IPM saw coal retirement far ahead with very deep early reductions, along with some of the other "push" policies, but it was found that the retired coal was backfilled with some imports associated with some fossil. Now the differences between the policies in IPM are looking smaller. Initially, the relative position of each policy did not change much; RGGI shows the biggest overall drop, followed by the clean energy standards, and then the carbon adder and coal retirements. However, by 2030, when considering imports, the CES becomes the lowest-emitting policy because it is driving a lot of in-state development of clean energy, and we end up relying more on in-state generation under a CES policy, reducing our imports and becoming an exporting state by the 2040s.

Total Emissions Reductions in 2030 (% change from 2005). A slide was shown presenting the emissions results for the same standard standalone policies seen before, but in a different format, with the addition of the emissions results for the combination policies. The standalone policies are shown against the combination "push and pull" policies. They don't look very different for 2030, but further into the future the combination policies start to work well with one another and we start to see complimentary policies and lower costs per ton as a result. These policies are defined in very particular ways, so the margins can be tweaked around how a particular policy would be designed, as mentioned in the report.

Policy Cost in Net Present Value. A slide with another metric is shown, comparing the same standalone policies with three versions of each: one for IPM (yellow), and two in DIEM (green). DIEM was run in two different ways since there was a lot of contentious discussion between stakeholders about a utility's payback period for new renewables, or the period over which they would ask ratepayers to pay. Some of the national labs started putting renewables on a 20-year payback schedule versus the traditional 30-year, which has huge implications when comparing costs, particularly for CES or combination policies that include a CES. The clean energy standards that are driving a lot of new renewables are showing a really big difference. A 41% difference in cost of clean energy standards was seen, depending on whether the Utilities Commission had those new renewables being paid over 20 or 30 years. Because it was such a contentious variable, the analysis went with the more conservative assumption, but then has sensitivities to show the difference if the Utilities Commission chose a different payback period. At the top of the graph is a dollar per ton value, which is also a net present value and shows the work that each policy is doing. Accelerated coal retirements, RGGI, and a CO_2 adder on new capacity, seem the least expensive overall, but looking at their price ranges helps to see how many reductions you are getting for those costs. The smaller the cost per ton, the more tons you are getting off the system from that policy. The low end of cost range for RGGI is negative $8.00 per ton. Two things were noted related to the meaning of this negative value. First, when RGGI was run with auctioning of allowances and investment in energy efficiency, it lowered demand overall and did not require building new capacity that otherwise needed to be built in the business-as-usual, resulting in lower overall system costs. Second, they do not have really precise numbers on the energy efficiency and the cost of deploying it in N.C., noting it is something they would like to work on in the future. So, those are not "take it to the bank" numbers, but show that an investment energy efficiency, whether clean energy standards or any other programs, did bring down costs due to bringing down overall demand.

Mr. Jonas talked about the Policy Costs in Net Present Value and the Local Air Pollution in 2030 (mmt).

Policy Costs in Net Present Value. Some affordability options were displayed, as it is one of the core values identified in the CEP. Some of the policy options control the total cost of a policy and some can control how cost is allocated over time or to particular customers. These fit more naturally within some policy options better than others, as the report identifies. There is some analysis on direct bill assistance, for example, the effects of carbon market auction revenue recycled into direct bill assistance.

Local Air Pollution in 2030 (mmt). In addition to GHG emissions impacts, the report also includes information about NOx and SOx impacts, partly because it may be one metric that helps evaluate the equity impacts. For the most part, the reductions of SOx and NOx track the reductions of GHG emissions. The major an exception is the carbon adder on capacity, the shadow price on building new generation, because by focusing on new generation, it means that less new natural gas is built, which means there is more reliance on old existing coal in the system.

Ms. Konschnik ended the presentation talking about the Changes in NC Capacity by 2030.

Changes in NC Capacity by 2030. The changes in North Carolina capacity were shown, with capacity being what is built and retired - the total megawatts installed capacity for generating electricity. The changes in generation were also mentioned, noting that these power plants are not always available or running at full tilt. It shows which combination of resources are being dispatched to meet electricity demand, with interesting trends that the report relates about different policies, such as driving retirements of something while driving generation of something else. Sometimes those trends can work together to decarbonize, while sometimes they work at cross purposes.

Q/A session

Chair Arata: asked whether Commissioners had questions. Chair Arata directed the first question to **Ms. Konschnik.** You mentioned that the models were highly responsive to modest changes in cost. Could you provide a sense of what a modest change would be?

Ms. Konschnik responded that those would be some of the "push" policies, where modest dollar amounts were enough to make a lot of the remaining coal uneconomic, those being the market-based, carbon adder, and RGGI policies. For instance, the stakeholders initially looked at a lot of numbers for shadow prices, or carbon adders on generation or new construction, including the 2015 social cost of carbon that has come out of the US government, which started at $42 per ton and went up quite steeply, as well as the 2017 social cost of carbon out of the Administration and a number of different adders. Ultimately, the one that started smallest, at $6 per ton in 2023, did enough work that it ending up being the standard carbon adder for both generation and new capacity because that small number was enough to make a big change on the system and there was not a need for a bigger price. Similarly, RGGI allowance prices were coming in between $4 and $5 per ton, which was also enough to push a lot of the coal offline.

Mr. Monast suggested to **Chair Arata** to include **Mr. Martin Ross** to expand the response about the sensitivity of the fuel prices changes and how that affected the projections. **Chair Arata** approved the request.

Mr. Ross responded. In terms of the modest question, there is a table in the executive summary of the report that has some cost percentage exchanges that may give a better sense for some of that, like a coal retirement policy that had around 0.5% increase in the system cost. The executive summary has some sensitivity analyses. Some of them have large effects, including natural gas prices assumptions, while others are a bit less dramatic, such as electricity demand growth. The natural gas price assumption started out relatively cheap for the next few years and then increases similar to the IRP assumptions, which helped with the retirement of coal units because the gas units are cheaper to run. Also, the coal units that are being retrofitted to burn either partially or totally natural gas, would be inclined to use natural gas in those circumstances, which also affects the emissions. Higher gas prices could potentially raise the policy cost by 50% or more. If using gas prices along the lines of what NREL used in their analysis, gas prices that were low today and stayed low would result in somewhat lower policy costs than what we saw. They also made assumptions in the report and show sensitivities, such as assuming it may be more costly to hook up a new combined cycle unit to the gas system and secure gas supplies for new combined cycle units that were going to be running in base load, which went a fair way towards preventing those types of units from becoming uneconomic. If you remove those assumptions, some of the policies could result in much higher construction of those type of units, which also plays through into the whole policy cost story.

Chair Arata indicated that **Chairman Meiburg** had questions.

Chairman Meiburg thanked the presenters for the presentation and proceeded to ask two questions: (1) what discount rates were used in calculating the net present value? and (2) because of their own carbon commitment, some industries are starting to look not only for the lowest dollars per ton or dollars per kilowatts cost, but also for composition of that in terms of meeting their own ESG goals. He is assuming the report does not get into the nuances of the power purchase agreements and how that matches with a regulated utility, which is whole other policy discussion, but asked if that was a factor in any of the analyses.

Ms. Konschnik directed the questions to **Mr. Ross**, and he responded. For discount rates, IPM typically is using 4.1%. Mr. Ross looked at various numbers, but ultimately used data from the NREL model, which is in the 4.1-4.2% range over the years. The models are solving for the most cost-effective way to provide electricity to the system. Regarding companies asking for particular types of generation, the closest this analysis comes would be offshore wind requirements added onto some of the policies where a particular type of generation was specified, but there is a lot more that could be done to represent those things.

Ms. Konschnik also added to the response. Stepping back from the modeling, that was part of the conversation in terms of what business want, and so coming out of CEP were core values of cost, affordability, and emissions reduction to keep in mind. The amount of renewables online was another core metric important to stakeholders. She referenced the ending slides that show which policies get the most diverse mix of generating units and which get in-state cleaner so that business here with ESG goals can say they are in a clean state. People were less interested in a policy that had more reliance on imports that they were unsure where they were coming from. People have concerns about cost, but there was a tradeoff of wanting to build clean in North Carolina and have that be attractive to businesses located here.

Chairman Meiburg followed up on the imports question, noting that they probably had to make assumptions about the carbon composition of imports, but utility systems that will be importing into North Carolina are going through the same kinds of transition and asked how that factored into the analysis of carbon loading from imports.

Ms. Konschnik directed the response to **Mr. Ross** to discuss how the model treats imports. **Mr. Ross** stated that they had to make assumptions about what was going on in other states. For Virginia, it was easy due to their Clean Economy Act in the models for Virginia. For imports coming from South Carolina, he excluded the Dominion coal plant in South Carolina when calculating the emission intensities of what was coming across the border, thinking it would more likely be the Duke units in South Carolina. There were a number of assumptions along those lines. More broadly in most of the policies, they tried to avoid making assumptions about actions other states may take in the future, so are probably somewhat over-stating the longer-term emissions intensity of the imports because major changes were not assumed outside of Virginia and RGGI. There were some policies that assumed national or federal implementation of a few things to see the impact on results.

Ms. Konschnik added, when looking at a scenario where there was a national clean air energy standard, the way the results changed from when North Carolina did that as an "island" suggested that NC has an advantage, and if there were to be broader policies, it seemed cost-effective to build here and then be selling clean energy credits to other states.

Chairman Meiburg asked whether, right now under the base case, energy imports are coming mostly from Virginia and South Carolina, and how TVA is factored.

Mr. Ross responded that TVA did not factor in too much in terms of their understanding of transmission lines, noting they would be fairly clean but limited, an assumption that the stakeholders agreed with.

Ms. Konschnik added that the imports are coming from South Carolina and Virginia. Virginia is getting cleaner based on their new policies, and South Carolina is still nuclear-heavy, which is a cleaner mix than you would get in other parts of the country from imports.

Mr. Monast responded to **Chairman Meiburg** in relation to his original question about different types of industrial customer having different goals. One of the reasons for the approach that was used for the question of affordability was to recognize different perspectives within groups of stakeholders. Some of these metrics for affordability were identified by Mr. Monast and the report goes into additional metrics for affordability, but they left it to the different stakeholders and policy makers to choose, while trying to make the metrics transparent. He emphasized that, when thinking about the cost and the numbers in the report, it critical to keep in mind that changes are taking place across the electricity system; it is not unique to North Carolina and is independent to whether other states adopt additional policies. So, cost will likely be going up all around us, which is important to keep in mind when comparing North Carolina and what happening elsewhere.

Commissioner Deerhake thanked the presenters and asked three questions: (1) will the evaluation of health and environmental benefits be included in the results? (2) with the regional nature of southern states participating in a northeastern group, would the northeastern states put any extra burden on southern states participating, or is it an equal market in terms of allowances prices by state? Are the state's rates negotiated or is there one price for all states?

Ms. Konschnik responded that the answer to the first question is unfortunately, no, which is made clear in the report that they did not monetize other non-energy benefits, such as health benefits or cost of inaction. There is a lot left that was not in the equation, but they did try to highlight certain outputs from the models and analyses, like the changes in NOx and SOx, to start to approximate that. Generally, those followed the trend of CO_2, but sometimes there is an increase in NOx pollution from some policies, so it is in the mix for people to trade off when deciding between policies. Regarding the second question, in the RGGI program, each state set its own budget for the number of allowances it is going to put out, which is part of a negotiation with other states. At the extreme, if they have an existing liquid functioning market, they would not want someone to put a lot excess of allowances into the market to devalue it, but the price is set by the exchange between utilities across the region. So, once each state puts in its allowances, those allowances are fungible. It is one regional market where every one is the same and has the same value, which is just what different generators are willing to buy or sell to each other. For example, a New Jersey plant that may be willing to buy from North Carolina, would buy at the same price as from someone in VA or Maryland. The cost is set by what the power generators are willing to buy and sell, which is the same across the region.

Mr. Monast added that how the allowance value translates to electricity rates can vary based on how North Carolina implements a carbon market, by free allowances vs. purchasing at auction. That can also vary depending on whether there is revenue generated by the program. If there is an auction, there are different options for using that revenue, such as investing in the types of the programs that can reduce electricity consumption, like efficiency programs, or for direct bill assistance or other options.

Commissioner Deerhake asked if they tried to design reliability scenarios into the model in terms of extreme weather conditions, grid reliability, or power source reliability.

Ms. Konschnik responded that they did not test external "knocks" to the system, such as another 500-year storm; that was beyond of the scope of the study but would be an interesting analysis due to the current dynamic situation.

Mr. Ross responded that the broadest way, there are always some reserve margins in the model. For most of the runs they used Duke IRP's assumption of 17% reserve margin, which is fairly conservative in terms of the amount of capacity you would need in the system to handle some of these extreme events. These models are not modeling individual shocks but normally they would address it through a reserve margin. Also, there are other types of reserve in terms of operating reserves on an hour-to-hour basis to make sure there is enough spinning at any given time to meet shorter-term fluctuations. He advised the results be interpretated with some caution in terms of whether a 17% reserve margin is sufficient.

Mr. Monast added that this is an important difference between this analysis and how Duke will model for their IRP when to planning for the future, in addition to dispatch, and how they actually operate different generation assets on the system and the extent to which they rely on them since North Carolina is connected to a large regional electric grid. There are other important models and tools that were not something attempted with this report.

Mr. Ross added that the models are doing what they can in these long-term settings to take into account what it will do to the system to have increasing amounts of renewables, and how to ensure some basic notion of reliability as the percentage of conventional fossil assets within the system declines and you move more towards intermittent resources. The models attempt to consider those type of issues.

Chair Arata indicated they were running behind time, but they had availability to take one more question.

Commissioner van der Vaart asked whether any attempt was taken to account for increased methane emissions as more natural gas moves into the mix.

Ms. Konschnik responded, noting it is a great question and was a topic of intense discussion during the CEP process and again at the beginning of the A-1 process. They ended up deciding to focus on CO_2 and the point of combustion. The report has a footnote flagging that a number of stakeholders disagreed, saying that they really needed to start looking at the life cycle accounting of emissions from different sources, and account for methane; it was a "scope call" more than anything else, so they disclosed that they didn't account for it, but it was of interest to a great number of stakeholders.

Discussion section was closed by **Chair Arata** thanking the speakers for the presentation.

Agenda Item V-2, Director's Remarks (Mike Abraczinskas, DAQ)

Due to the constraint of time, the Director's remarks were not presented.

CLOSING REMARKS AND MEETING ADJOURNMENT

Chair Arata thanked again the speakers for the presentation and noted that the next meeting of the AQC is scheduled for May 12, 2021. **Chair Arata** adjourned the meeting.