BEFORE THE NORTH CAROLINA UTILITIES COMMISSION

DOCKET NO. E-2, SUB 1204

| In the Matter of | | |
|---|---|---|
| Application by Duke Energy Progress, LLC Pursuant to G.S. 62-133.2 and Commission Rule R8-55 Regarding Fuel and Fuel-Related Costs Adjustments for Electric Utilities | )<br>)<br>)<br>)<br>)<br>) | TESTIMONY OF<br>DUSTIN R. METZ<br>PUBLIC STAFF – NORTH CAROLINA UTILITIES COMMISSION |

**Q. PLEASE STATE YOUR NAME AND ADDRESS FOR THE RECORD.**

A. My name is Dustin R. Metz. My business address is 430 North Salisbury Street, Raleigh, North Carolina.

**Q. WHAT IS YOUR POSITION WITH THE PUBLIC STAFF?**

A. I am an engineer with the Electric Division of the Public Staff representing the using and consuming public.

**Q. WOULD YOU BRIEFLY DISCUSS YOUR EDUCATION AND EXPERIENCE?**

A. A summary of my education and experience is outlined in detail in Appendix A of my testimony.

**Q. WHAT IS THE PURPOSE OF YOUR TESTIMONY IN THIS PROCEEDING?**

A. The purpose of my testimony is to present the Public Staff's recommendations regarding the proposed fuel and fuel-related cost factors for the residential, small general service, medium general service, large general service, and lighting customers of Duke Energy Progress, LLC (DEP or the Company), as set forth in the Company's June 11, 2019, application and the Company's August 15, 2019 supplemental filing.

**Q. WHAT ARE THE TEST AND BILLING PERIODS FOR THIS PROCEEDING?**

A. For this proceeding, the test period is April 1, 2018 through March 31, 2019, and the billing period is December 1, 2019 through November 30, 2020.

**Q. PLEASE DESCRIBE THE SCOPE OF THE PUBLIC STAFF'S INVESTIGATION.**

A. The Public Staff's investigation included a review of the Company's test period and projected fuel and fuel-related costs and also the following: (1) the Company's application, testimony, and responses to Public Staff data requests; (2) documents related to the performance of the Company's baseload power plants, including the specific performance of the Company's nuclear facilities; (3) the Company's purchased power transactions, including from renewable energy facilities;[1] (4) the Company's coal, natural gas, nuclear, and reagent procurement practices and contracts; and (5) the current state of coal, natural gas, nuclear fuel, and reagent markets. The Public Staff also engaged in multiple discussions and meetings with Company personnel regarding these subjects and conducted a site visit to the H.B. Robinson Nuclear Station

[1] Except for those costs recovered pursuant to N. C. Gen Stat. § 62.133.8(h).

(Robinson). I have also reviewed the testimony of Public Staff witnesses Jenny Li and Jay Lucas.

**Q. PLEASE SUMMARIZE THE RESULTS OF YOUR INVESTIGATION AND YOUR RECOMMENDATIONS.**

- For the test year, the Company did not meet the standard found in Commission Rule R8-55(k), and the Public Staff disagrees with the Company's inputs into the calculation of averages. The Public Staff believes it is reasonable in this case to factor in the effects of hurricane-related events. Factoring in those effects, the Company meets the standard.
- The Public Staff cannot conclude that an outage extension at Robinson was unavoidable and the resulting replacement power costs were reasonably and prudently incurred due to an absence of documentation.
- The Public Staff is concerned about the Company's natural gas commodity pricing methodology and believes it warrants further analysis by the Company.

## Commission Rule R8-55(k) Standard

**Q. DURING THE TEST YEAR, DID THE COMPANY ACHIEVE EITHER OF THE TWO BENCHMARKS SET FORTH IN SUBSECTION (K) OF COMMISSION RULE R8-55?**

A. No. For the test year, the Company did not meet either of the two benchmarks set forth in Commission Rule R8-55(k). The Company reported a single year system-wide nuclear capacity factor of 89.21%, which was less than the NERC (North American Electric Reliability Corporation) weighted average nuclear capacity factor. Additionally, the Company's two-year simple average of its system-wide nuclear capacity factor of 92.44% was also less than the NERC weighted average nuclear capacity factor (CF). Therefore, a rebuttable presumption was created that DEP imprudently incurred the increased fuel costs during the test year.

**Q. WHAT IS THE MOST RECENT NORTH AMERICAN ELECTRIC RELIABILITY CORPORATION'S (NERC) GENERATING AVAILABILITY REPORT (GAR) CAPACITY FACTOR (CF)?**

A. The most recent NERC GAR CF[2], appropriately weighted for the size and type of plants that are equivalent to the Company's, is 92.72%.[3]

**Q. DO YOU AGREE WITH THE COMPANY'S INPUTS TO DETERMINE THE SINGLE AND TWO YEAR AVERAGES?**

[2] On July 30, 2019, NERC issued is annual updated Generating Unit Statistical Brochure (e.g., GAR). As a result, I believe the most current values should be used for evaluation purposes. This date is the earliest in which NERC has released the Generating Unit Statistical Brochure over the last four years.

[3] At the time of the Company's filing, the 2013-2017 GAR was the most recent release, and the benchmark weighted average was 91.80 CF% versus the 2014-2018 benchmark weighted average of 92.72% CF.

A. No, I do not completely agree with the Company's inputs used to determine its comparative averages to the NERC GAR CF. While my disagreement results in a CF difference that is immaterial to the end result in this case, it may not be so in the future; thus I would like to bring the differences to the Commission's attention.

In this particular docket, the name plate rating or maximum dependable capacity (MDC) for the Shearon Harris Nuclear Station (Harris) is of interest. In the 2018 spring nuclear refueling outage, at the beginning of the Company's test year, Harris underwent a replacement of its low pressure turbine, adding 32 megawatts (MW) of station capacity.[4]

I do not take issue with how the Company tested and validated the results of the low pressure turbine replacement throughout the 2018 test year, as described by DEP witness Kelvin Henderson. However, based upon my review of the Harris generation profile, when calculating the annual (test year) CF, the additional 32 MWs of station capacity should have been included, beginning when the outage was completed. Including the increase in the available dependable generation post installation better aligns the actual fleet performance to peer units. To do otherwise allows the DEP unit and fleet to take seven months of operational credit at an understated

[4] Direct Testimony of Company witness Henderson, p. 10.

capacity value. In other words, the Company's filed calculation evaluates the Harris actual generation performance against an unrealistically lower theoretical generation performance target. For example, Table 1 below is an extraction of data from the Company's monthly Baseload Power Plant Performance Reports filed with the Commission.[5] In the first full month of production following the planned refueling outage, the plant experienced a 104.5% CF, which never dropped below 103% CF for the remainder of the test year, reaching a maximum of 107.3% in November of 2018. Harris remained at a generation capacity factor greater than 104% CF for the entire summer of 2018, which is particularly notable because summer is typically a time when generating plants are forced to operate at lower output due to increased thermal temperatures of cooling water. The Company finally updated the plant's MDC rating in January of 2019, nearly seven months after the unit underwent a power uprate.

| 2018 | | | | | | | | | 2019 | | |
|---|---|---|---|---|---|---|---|---|---|---|---|
| Apr | May | Jun | Jul | Aug | Sep | Oct | Nov | Dec | Jan | Feb | Mar |
| 19.2% | 66.3% | 104.5% | 104.5% | 104.4% | 104.5% | 105.8% | 107.3% | 107.0% | 103.7% | 103.4% | 103.0% |

**Table 1**: Shearon Harris Nuclear Station Test Year Capacity Factors

As I stated earlier, I believe it is important to compare a generation unit's actual performance under the R8-55(k) guidelines by using

[5] Docket No. E-2, Subs 1164 and1201.

the most accurate data set. Absent this type of adjustment (i.e., correcting the unit MDC value to a contemporaneous post installation level versus waiting seven months), deviations in generation output can improperly skew the single year weighted average and the two year simple average.

While this calculation adjustment has no material impact to the comparative analysis required by the R8-55(k) guidelines in this case, it has created some discrepancies between the values discussed in my testimony. This single year variance between the DEP calculation and my corrected calculation is approximately 0.61%.[6]

**Q. IN TABLE 1, YOU LISTED A CF TABLE FOR HNS. DO YOU HAVE OTHER EXAMPLES OF COMPANY NUCLEAR PLANTS EXCEEDING 100% CF DURING SUMMER MONTHS?**

A. Yes. As noted above, summer months will typically have the lowest annual dependable capacity rating due to increased thermal temperatures of the cooling water. Tables 2 and 3 provide the previous test year CF values for both Robinson and Harris, and show that a number of months' CFs exceeded 100%. Units that

[6] According to DEP witness Henderson, DEP calculated a single year weighted CF of 89.21%. The Public Staff calculated a single year value of 88.60%. According to witness Henderson, the two year simple average resulted in a 92.44% CF; the Public Staff calculated a value of 92.08% CF. The NERC GAR CF of 92.72% is the comparative value to the DEP single year and two year average.

consistently and regularly exceed a CF of 100% warrant closer scrutiny and an increase in the MDC.

| 2017 | | | | | | | | | 2018 | | |
|---|---|---|---|---|---|---|---|---|---|---|---|
| Apr | May | Jun | Jul | Aug | Sep | Oct | Nov | Dec | Jan | Feb | Mar |
| 73.5% | 102.7% | 102.0% | 100.8% | 101.1% | 102.7% | 103.2% | 104.9% | 107.6% | 107.9% | 107.3% | 107.2% |

**Table 2:** H.B. Robinson 2018 Test Year Capacity Factor

| 2017 | | | | | | | | | 2018 | | |
|---|---|---|---|---|---|---|---|---|---|---|---|
| Apr | May | Jun | Jul | Aug | Sep | Oct | Nov | Dec | Jan | Feb | Mar |
| 103.0% | 102.7% | 101.9% | 101.2% | 101.5% | 100.9% | 80.7% | 104.2% | 104.2% | 85.6% | 102.7% | 103.3% |

**Table 3:** Shearon Harris 2018 Test Year Capacity Factor

**Q. DID YOU TAKE INTO CONSIDERATION THE TEST YEAR HURRICANE-RELATED WEATHER IMPACTS ON THE BRUNSWICK NUCLEAR UNITS WHEN YOU CONSIDERED THE CAPACITY FACTOR BENCHMARK COMPARATIVE STANDARDS SET FORTH IN COMMISSION RULE R8-55(K)?**

A. Yes I did. Because the Company did not meet either of the benchmarks (guidelines) set forth in R8-55(k), a presumption of imprudence was created that some portion of the cost of fuel and fuel-related costs incurred by the Company warranted disallowance in this case. My analysis of the test year performance of the Brunswick Nuclear Station (Brunswick) units confirms the testimony of DEP witness Henderson that the test year weather-related events that caused Brunswick Units 1 and 2 to be offline were beyond the Company's control. Therefore, I requested that the Company recalculate the single and two year average CFs by removing the Brunswick weather-related outages. After this recalculation, the single year weighted average CF continued to be less than the NERC GAR CF value, regardless of which Harris MDC value (see discussion above) was used for the current test year.[7] However, the recalculated two year simple average met the NERC GAR CF value.[8]

**Q. WHY DIDN'T YOU INCLUDE THE ROBINSON EXTENDED FALL 2018 OUTAGE IN THE RECALCULATED HURRICANE-RELATED CFS?**

A. First, as discussed previously, removal of the Brunswick hurricane-related outages allowed the Company to exceed the two year simple average CF due in part to the previous year's approximate 96% overall CF. Thus, the rebuttable presumption of imprudence was avoided.

Second, the Robinson 67 day outage, which included a scheduled 39 day refueling and transmission project outage, had an outage delay associated with, at least in part, weather events. My review of

[7] DEP recalculated a single year weighted average CF of 90.39% with the Brunswick Hurricane Florence outages removed, but using its filed MDC for Harris, I calculated an 89.78% single year weighted average CF with the adjusted MDC for Harris discussed previously.

[8] DEP recalculated a two year simple average CF of 93.02% with the Brunswick Hurricane Florence outages removed, but using its filed MDC for Harris. I calculated a 92.72% two year simple average CF with the adjusted MDC for Harris discussed previously.

the total outage involved an assessment of how the scheduled outage had progressed prior to the weather-related events, and an assessment of any associated impacts on the 28 day outage extension.

**Q. PLEASE PROVIDE A SYNOPSIS OF THE 2018 FALL OUTAGE AT ROBINSON.**

A. As discussed in greater detail in DEP witness Henderson's testimony, part of the outage scope was to install a transmission upgrade project (TUP). The TUP was a multiyear design, procurement, installation, and commissioning project that began in 2011, with a proposed in-service date of Spring 2017.[9] The multi-year coordinated TUP project, included installing a new 230 kV start-up transformer, replacing an existing 115 kV start-up transformer, switchyard modifications, replacing older electro-mechanical relays with digital relays, building infrastructure, installing new electrical switchgear, replacing reactor coolant pump breakers, installing uninterrupted power supplies and battery systems, and numerous other electrical systems. The overall scope of this project was expansive and required a significant level of engineering and oversight.

[9] Initial communications with the Company revealed the initial in-service date of 2014 and not 2017. This was later clarified in discovery, and the overall project was completed in stages, spanning multiple outages and years.

After investigation, I am unable to conclude whether the additional 28 outage days of replacement power costs incurred during the Fall 2018 outage at Robinson were imprudently incurred. I will discuss the factors that led to my inconclusive determination below.

**Q. MR. METZ, IF YOUR FINDINGS ARE INCONCLUSIVE, SHOULD THE COMMISSION DISALLOW THE REPLACEMENT POWER COSTS ASSOCIATED WITH THE 28-DAY OUTAGE EXTENSION?**

A. At this time I cannot recommend disallowance of any portion of the replacement power costs because the Fall 2018 outage was impacted, at least in part, by events outside of the Company's control (weather).

However, there is significant doubt, in my professional opinion, as to whether the Company's management of the project should have resulted in it being shifted from the Spring 2017 refueling outage to the Fall 2018 refueling outage.

In this case, I am faced with a dilemma in presenting my recommendation to the Commission. On the one hand, I cannot conclude with a reasonable certainty that the TUP was prudently managed up to the events that caused the outage to shift from 2017 to 2018. I will provide more detail on the factors that contributed to this decision later. At the same time, I cannot conclude that it is reasonable to disallow recovery of the replacement power costs for an outage that was impacted by severe weather events.

**Q. WHAT FACTORS PREVENTED YOU FROM REACHING A CONCLUSION AS TO WHETHER THE TUP PROJECT WAS PRUDENTLY MANAGED?**

A. First, the Company's lack of document access or retention restricted the Public Staff's ability to review and evaluate the prudency of project management. Let me expand upon some of the factors that may have contributed to the absence of sufficient documentation.

This particular project started pre-merger[10] and during the project life cycle, the merger led to the introduction of new policies and procedures regarding project management. The Company was able to produce applicable guidelines and procedures that should have been followed, but the documentation to ensure that these items were, in fact, appropriately implemented and completed could not be produced consistently.

This project had multiple internal project managers, at least two, over the project life as well as multiple iterations of project staffing. A significant portion of the information required to perform an evaluation of prudence is based upon the organizational

[10] When I reference "merger" in this testimony, I am referring to the merger of Duke Energy Corporation and Progress Energy, Inc. in 2012.

management by the project manager. The most recent project manager who worked on this project has since retired from the Company and, therefore, his knowledge of project specific events was not available to be utilized in this investigation. The Company was able to produce other project management staff who worked on the project, which did help the overall investigation, but there were still missing pieces.

The scope of this project would have required an immense amount of contractor coordination, not only with individual vendors, but also coordination of internal review cycles due to interdependencies among multiple working groups and project milestones. This level of communication would have required several revisions to project milestones, as well as numerous amounts of communication and records. As part of our discovery, the Public Staff asked the Company for "all" communications between the Company and vendors as well as any internal communications regarding the project. The Company was capable of providing only limited communications. As of August 1, 2019, only approximately five responsive documents had been provided.

While I believe that the Company worked in good faith to respond to Public Staff discovery, made technical experts and senior management available for discussion, and had open dialogue as the

Public Staff and DEP worked through the discovery process, I am concerned about the Company's apparent lack of records retention in this case. As the Commission relies on the Public Staff to conduct detailed technical and prudency investigations and audits of the utilities, I believe the Commission expects the utilities to retain adequate and sufficient documentation for audit purposes. Even though my testimony in this docket is about fuel and fuel-related costs associated with this proceeding, this concern has broader implications that could impact future investigations and proceedings. To that point, because the Robinson TUP project was completed in 2018, the associated capital expenditures specific to this project are not yet included in rate base. In the Company's next general rate case, we anticipate that the Company will seek cost recovery for the project, as the project is now completed. When the Company files a general rate case, the reasonableness and prudence of the project and project spend will be evaluated. The Public Staff will ask questions in the general rate case similar to those asked in this case, but the responses will be reviewed under a different lens (capital versus replacement power).

Having access to documentation is vitally important to the Public Staff's ability to audit and provide recommendations to the Commission. Commission Rule R8-28 establishes the records retention requirements of utilities, but it appears the Company did not fully comply with the Rule with respect to this project.[11] More likely than not, there are other Company projects that will require similar scrutiny, including legacy projects that occurred before, during, and just after the merger time period and transition, or other projects that span multiple years. Therefore, the Public Staff requests that the Commission (1) review the Company's records retention protocol to determine if it is consistent with the Commission's Rules and (2) provide guidance on how to proceed if necessary records are unavailable to allow sufficient review of projects or other items for which the Company seeks cost recovery.

**Q. ABSENT THE ROBINSON TUP PROJECT, DID YOUR INVESTIGATION INTO DEP'S OTHER TEST YEAR POWER PLANT OUTAGES REVEAL ANY UNREASONABLE OR IMPRUDENT ACTIONS BY THE COMPANY THAT WARRANT A DISALLOWACE OF REPLACEMENT POWER COSTS?**

A. No, my investigation did not reveal any other outages that warranted an adjustment in this proceeding.

[11]Commission Rule R8-28 requires that unless otherwise specified by the Commission, records must be retained in accordance with the National Association of Regulatory Utility Commissioners' (NARUC) publication "Regulations to Govern the Preservation of Records of Electric, Gas and Water Utilities." http://www.psc.state.wv.us/scripts/webdocket/ViewDocument.cfm?CaseActivityID=236040&NotType=%27%27WebDocket%27%27. Notably, the NARUC regulations provide that notwithstanding any minimum requirements in the regulations, utilities must retain appropriate records to support cost recovery.

## Future Commodity Pricing

**Q. DO YOU HAVE ANY CONCERNS ABOUT THE COMPANY'S NATURAL GAS COMMODITY PRICING METHODOLOGY?**

A. Yes, we have concerns about the Company's natural gas commodity pricing methodology, similar to the concerns expressed by Public Staff witness Jay Lucas in Duke Energy Carolinas, LLC's (DEC) recent fuel proceeding in Docket No. E-7, Sub 1190. As the Company has shifted to a fuel commodity with greater price variances (compared to nuclear and coal), despite overall decreasing costs in order to more economically serve its rate payers, these same customers are exposed to greater risk of fuel cost under- and over-recoveries. Natural gas consumption, most notably by baseload combined cycle (CC) plants, coupled with recent winter weather events of the last few years, have caused exposure to higher than anticipated natural gas fuel commodity prices.

**Q. DO YOU PROPOSE A SPECIFIC RECOMMENDATION TO ADDRESS YOUR CONCERNS?**

A. Yes. In the recent DEC fuel proceeding, the Commission required DEC to evaluate historic price fluctuations and whether its current method of forecasting and hedging programs should be adjusted to mitigate the risk of significant under-recovery of fuel costs and report the results of that evaluation in the Company's next fuel proceeding. DEP should be required to undertake the same evaluation and report the results to the Commission in its next fuel proceeding.

**Q. DID THE PUBLIC STAFF REVIEW THE BILLING PERIOD OR PROJECTED FUEL AND FUEL-RELATED COSTS AS SET FORTH BY THE COMPANY IN THIS FILING?**

A. Yes. Based upon my investigation, I determined that the projected fuel and reagent costs are reasonable and were calculated appropriately with the exception of CertainTeed-related costs, as discussed by Public Staff witness Lucas. The projected cost of fuel and fuel-related costs are affected by minor projected fluctuations in nuclear fuel, coal, and natural gas costs. DEP's proposed fuel and fuel-related costs are based on a 94.62% system nuclear capacity factor, which is what the Company anticipates for the billing period.

**Q. PLEASE DISCUSS THE PUBLIC STAFF'S INVESTIGATION OF THE TEST PERIOD EXPERIENCE MODIFICATION FACTOR (EMF).**

A. Public Staff witness Jenny X. Li describes the Public Staff's review of the test period EMF in her testimony, and I have incorporated her recommendations in Exhibit 1-Table 2 below.

**Q. WHAT ARE THE FUEL COMPONENTS AND TOTAL FUEL FACTORS THAT THE PUBLIC STAFF RECOMMENDS THAT THE COMMISSION APPROVE?**

A. The Public Staff recommends approval of the fuel components and total fuel factors (excluding the regulatory fee) shown in Exhibit 1 Table 2, effective for the twelve months beginning February 1, 2019:

**Q. DOES THIS CONCLUDE YOUR TESTIMONY?**

A. Yes, this concludes my testimony.

**APPENDIX A**

## QUALIFICATIONS AND EXPERIENCE

DUSTIN R. METZ

Through the Commonwealth of Virginia Board of Contractors, I hold a current Tradesman License certification of Journeyman and Master within the electrical trade, awarded in 2008 and 2009 respectively. I graduated from Central Virginia Community College, receiving Associates of Applied Science degrees in Electronics and Electrical Technology (Magna Cum Laude) in 2011 and 2012 respectively, and an Associates of Arts in Science in General Studies (Cum Laude) in 2013. I graduated from Old Dominion University in 2014, earning a Bachelor of Science degree in Engineering Technology with a major in Electrical Engineering and a minor in Engineering Management. I am currently enrolled at North Carolina State University, working toward a Masters of Engineering degree.

I have over 12 years of combined experience in engineering, electromechanical system design, troubleshooting, repair, installation, commissioning of electrical and electronic control systems in industrial and commercial nuclear facilities, project planning and management, and general construction experience, including six years with direct employment with Framatome, where I provided onsite technical support, craft oversight, engineer change packages and participated in root cause analysis teams at commercial nuclear power plants, including plants owned by both Duke and Dominion.

I joined the Public Staff in the fall of 2015. Since that time, I have worked on general rate cases, fuel cases, applications for certificates of public convenience and necessity, service and power quality, customer complaints, North American Electric Reliability Corporation (NERC) Reliability Standards, nuclear decommissioning, National Electric Safety Code (NESC) Subcommittee 3 (Electric Supply Stations) member, avoided costs and PURPA, interconnection procedures and power plant performance evaluations; I have also participated in multiple technical working groups and been involved in other aspects of utility regulation.

# EXHIBIT 1

## Proposed Fuel and Fuel-Related Cost Factors in cents per kWh effective December 1, 2019 (excludes regulatory fee)

**TABLE 1 – Company PROPOSED Fuel and Fuel-Related Cost Factors**

**(¢ per kWh)**

| Rate Class | Base & Prospective | EMF | EMF Interest | Total Fuel Factor |
|---|---|---|---|---|
| Residential | 2.344 | 0.394 | 0 | 2.738 |
| Small General Service | 2.527 | 0.217 | 0 | 2.744 |
| Medium General Service | 2.468 | 0.236 | 0 | 2.704 |
| Large General Service | 2.056 | 0.666 | 0 | 2.722 |
| Lighting | 2.281 | 0.548 | 0 | 2.829 |

**TABLE 2 – Public Staff PROPOSED Fuel and Fuel-Related Cost Factors**

**(¢ per kWh)**

| Rate Class | Base & Prospective | EMF | EMF Interest | Total Fuel Factor |
|---|---|---|---|---|
| Residential | 2.326 | 0.373 | 0 | 2.699 |
| Small General Service | 2.499 | 0.198 | 0 | 2.697 |
| Medium General Service | 2.456 | 0.218 | 0 | 2.674 |
| Large General Service | 2.054 | 0.648 | 0 | 2.702 |
| Lighting | 2.217 | 0.530 | 0 | 2.747 |

For comparison, Table 3 below provides the existing fuel and fuel-related cost factors (excluding the regulatory fee) approved in Docket No. E-7, Sub 1173:

**TABLE 3 – EXISTING Fuel and Fuel-Related Cost Factors (¢ per kWh)**

| Rate Class | Base & Prospective | EMF | EMF Interest | Total Fuel Factor |
|---|---|---|---|---|
| Residential | 2.311 | 0.575 | 0 | 2.886 |
| Small General Service | 2.556 | 0.363 | 0 | 2.919 |
| Medium General Service | 2.477 | 0.343 | 0 | 2.820 |
| Large General Service | 1.757 | 1.038 | 0 | 2.795 |
| Lighting | 2.251 | 0.885 | 0 | 3.136 |