Risks to Ratepayers

An Examination of the Proposed William States Lee III Nuclear Generation Station, and the Implications of "Early Cost Recovery" Legislation

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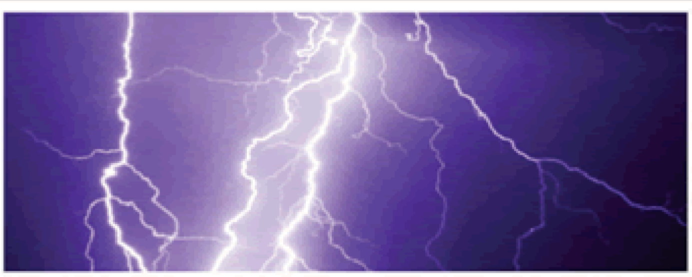

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1. Executive Summary

Until very recently, it had been more than three decades since a new nuclear power plant was ordered in the United States. Now, in 2012, developers are pushing forward with a new generation of nuclear power plants. In the first few months of 2012, the U.S. Nuclear Regulatory Commission (NRC) approved applications for the construction of four new reactor units: Vogtle 3 and 4 in Georgia, and VC Summer 2 and 3 in South Carolina.[1]

While this has not been the “Nuclear Renaissance” touted a few years ago, the slow reawakening of the nation’s nuclear power industry is generating considerable debate—in part due to the costly bailouts asked of American tax- and ratepayers to cover hundreds of billions in cost overruns and plant abandonments in the past, coupled with soaring price tags for many proposed reactors.

In the U.S., the states of Florida, Georgia, and South Carolina have passed legislation that allows utilities to recover annually the financing costs for nuclear power plants from electric customers (via electric rates) during the construction process—long before the plants may or may not become operational. Generally, this legislation is known as nuclear Construction Work in Progress (CWIP).[2]

Under these annual nuclear CWIP laws, ratepayers, not the company shareholders, are bearing the financial risk of the proposed plants.[3] Moreover, these laws do not place a cap on the risk to ratepayers; utilities are able to recover financing costs whether or not the proposed nuclear plants are completed, and no matter how much they cost in the end. Ratepayers in those three states are effectively in a “pay as the company goes” scenario, since Commissions have approved annual rate increases that allow the companies to recover the financing component of the construction costs. Ratepayers in Georgia, Florida, and South Carolina are currently paying for plants whose costs are unknown, whose completion dates are unknown, and whose completion is uncertain.

Currently, North Carolina has a weaker version of this CWIP recovery mechanism, allowing Duke Energy to petition the commission for recovery, but with no guarantee of success. However, Duke Energy Carolinas (Duke) is now advocating for legislation in North Carolina that would allow Duke to subject ratepayers to virtually automatic annual rate increases during construction of the project, whether or not the reactors ever come on line. This would be nearly identical to the South Carolina legislation, and would compel Duke’s electricity customers in the state to bear a much larger share of the risks associated with its proposed William States Lee III (Lee) nuclear reactors.[4]

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[1] http://pbadupws.nrc.gov/docs/ML1204/ML120410133.pdf and http://www.nrc.gov/reading-rm/doc-collections/news/2012/12-034.pdf

[2] The proposed North Carolina legislation also removes a commission’s ability to revisit costs once commercial operation commences for the plant ,if the plant has undergone a review process.

[3] In an April 11, 2012, presentation held at the Center for Strategic and International Studies, Exelon CEO, Mayo Shattuck, reiterated that ratepayers, not shareholders, will bear the risk of new nuclear construction in the United States.

[4] On August 7, 2012, the Nuclear Regulatory Commission (NRC) suspended new license and license renewal requests, pursuant to a US Court of Appeals DC Circuit ruling on long-term storage of radioactive waste at nuclear plants. We do not know when or how the NRC will resolve this issue, but the effect may result in delays or changes to the proposed Lee plant.

For Duke Carolinas ratepayers, the rate increases from a proposed Lee project would compound recent and anticipated rate increases associated with scheduled plant additions that have yet to be fully incorporated into rates, as detailed in Appendix A.

This report—following in part on a 2011 Synapse report examining proposed nuclear plants in Georgia and Florida—takes a close look at the proposed Lee nuclear power plant to more clearly identify the costs and risks to ratepayers. We also put these costs and risks in the context of numerous recent and forthcoming rate increases facing Duke's customers in North Carolina.

This study further draws comparisons between the proposed Lee project and the South Carolina Electric and Gas (SCE&G) VC Summer nuclear project, currently under construction in South Carolina, which shares several key physical and financial characteristics with the Lee project. Both of these projects:

- Use the Westinghouse AP1000 reactors
- Consist of two units
- Have an estimated capacity factor of 2,234 megawatts (MW)
- Do not have the benefit of Federal Loan Guarantees
- Have (or are seeking) early financing cost recovery from ratepayers (SCE&G has already begun charging annually its ratepayers for the financing costs associated with VC Summer project.)

Examination of VC Summer is also significant because Duke is considering purchasing a portion of this project, which is scheduled for completion in 2017 (Unit 1) and 2019 (Unit 2). SCE&G owns 55% of this project and Santee Cooper owns the other 45%. Santee Cooper is interested in selling some portion of its ownership stake to other utilities, including the now-merged Duke and Progress Energy Carolinas.[5]

If early financing cost recovery legislation is passed in North Carolina, and Duke acquires a share of the VC Summer plant, ratepayers in that state may have to pay early financing costs associated with *both* the VC Summer project and the Lee units. Assuming regulators reaffirm approval of the Duke Progress merger[6] and both Duke and Progress each acquire 10% ownership stakes from Santee Cooper, then Duke may own up to 20% of the VC Summer project.

Key Findings

Our analysis finds that there are major risks associated with the construction of the Lee project. While the AP1000 reactor represents a more standardized design than existing U.S. reactors, it has never been built in this country nor completed in any country. Nuclear power construction is still a very complicated process with numerous unknowns that can negatively impact plant

[5] http://www.powermag.com/POWERnews/3898.html?hq_e=el&hq_m=2250570&hq_l=10&hq_v=30108e0773. Santee Cooper is a state-owned water and electric utility. We understand that Duke and Progress Energy are both in discussions with Santee Cooper for each utility to purchase up to a 10% ownership stake of the project from Santee Cooper.

[6] Although the merger was completed on July 2, 2012, new questions have arisen as a result of the almost immediate ouster of Bill Johnson as CEO of the merged entity, despite his designation as the CEO in all merger filings. This has resulted in a number of lawsuits filed on behalf of shareholders of both companies. .

economics. Risks for this project include cost escalation, construction and regulatory delays, and lack of transparency, all of which could lead to much higher costs to ratepayers.

In terms of bill impacts, Duke has not publicly presented analyses calculating monthly costs to ratepayers associated with the Lee project; Duke has kept this information confidential. Since no bill impact analyses have been provided by Duke for the Lee project, this study estimates bill and rate impacts—including low-, mid-, and high-case estimates—using information from Duke's 2011 rate case. While the 2011 rate case requested a substantial rate increase from Duke's ratepayers over those set in Duke's 2009 rate case, this increase was independent of (and in addition to) the future rate hikes likely to result from early recovery of nuclear plant construction costs and other plant additions. These rate increases are detailed in Appendix A.

We summarize key findings below:[7]

- Our low estimate is an "all-in" Lee project cost[8] of $20.7 billion (in 2024 dollars), based on the Company's current anticipated project cost and completion schedule. In 2010 dollars this would amount to be $16.3 billion. Based on this "low" estimate, the annual impact in 2022 on a typical[9] residential customer would be approximately $1,312, or a 18% increase from current 2012 rates, holding all other factors constant.[10]
- Our high estimate is an "all-in" project cost of $41.5 billion (in 2024 dollars), based on the 103% increase in Duke's estimated project cost between 2007 and 2010, and the Company's current completion schedule. In 2010 dollars this would amount to be $32.7 billion. Based on this "high" estimate, the annual impact in 2022 on a typical residential customer using would be approximately $1,465, or a 35% increase from current 2012 rates. As noted above the current rates, set in 2011, were already substantially higher than those set two years earlier.
- Our mid estimate is an "all-in" project cost of $31.1 billion (in 2024 dollars), based on a percentage of our high-estimate cost trajectory and the Company's current completion schedule. In 2010 dollars this would amount to be $24.6 billion. Based on this "mid" estimate, the annual impact in 2022 on a typical residential customer would be approximately $1,378, or a 26% increase from current 2012 rates.

Based on actual historic changes in Duke's estimates, and the experience of other nuclear construction projects underway in the United States, Finland, and France, which are experiencing significant delays and cost overruns, it is likely that the mid- or high-level estimates are more appropriate expectations of likely costs.[11]

[7] In this report, we report our estimates in two different components to maintain some consistency between various press releases and future construction budgets. Our estimates for total project costs and bill impacts are presented in constant 2023 dollars based on the current completion date. Our levelized cost estimates are reported in constant 2010 dollars to remain consistent with Synapse's previous studies on proposed nuclear power plants.
[8] The "all-in" costs include financing costs and general inflation.
[9] The bill impact is based on a monthly usage of 1,000 kWh.
[10] The rate impact of the proposed Lee plant would be higher compared to Duke's 2009 rates. The Company's 2009 rates reflect the last set of rates before the Company's period of more frequent rate cases (2009 and 2011).
[11] Construction of Watts Bar Unit 2 was restarted in 2007 after being halted in 1988. Since restarting, the completion date of the unit has slipped from 2012 to 2015. Appendix B details problems at Flamanville 3 and Olkiluoto in France and Finland respectively.

It is important to note that the high estimate is in line with the cost overruns experienced by the previous generation of nuclear plants; however, it does not represent an upper limit on potential costs for the Lee project.

Although the Lee project has yet to be approved by the NRC or the North Carolina Utilities Commission (NCUC), the proposed "overnight" plant cost estimates have doubled from 2007 to 2011 in real terms, from $6 billion to $13.1 billion (2010$). Furthermore, the anticipated completion date has moved back ten years, from 2015 to 2024. These trends, alone, point to major risks for ratepayers.

The lack of transparency surrounding this project exposes Duke's ratepayers to risk, by hindering independent analyses of the Company's cost and schedule assumptions.

Policy Implications

While we cannot know with certainty the final cost of the proposed Lee project, we do know that the overall trend for nuclear projects (and other large-scale construction projects) is one of increasing costs.[12] (This trend is discussed in detail in Appendix B.) There is considerable reason to believe that the Lee project will present much greater risks and costs for ratepayers than those anticipated by the projects' sponsors—especially if North Carolina adopts early financing cost recovery legislation similar to the laws that currently exist in Florida, Georgia, and South Carolina. These risks and costs will only increase for Duke ratepayers if the company purchases an ownership fraction of the VC Summer project, since VC Summer would have similar completion and cost risk.

If the project cost and schedule were fixed and guaranteed, then pre-paying financing costs could reduce "rate shock" to ratepayers once the project comes on line, relative to a traditional ratemaking approach. Traditional ratemaking generally allows capital projects to be incorporated into rates when "used and useful." Under this traditional approach, the construction and financing costs would go into the rate base and customers would start paying down the full cost once the plant goes into service.

With the proposed ratepayer financing, the total amount that would go into the rate base would be reduced, but only because the customers would have already been paying annual financing costs before the plant begins operation—effectively an interest-free loan from ratepayers to the company and its shareholders. The project appears less costly, but only because ratepayers have already paid the financing costs of the bills. Another concern is that with customers effectively financing the project, there is less incentive for the company to control project costs thus potentially raising the cost for ratepayers in the end.

However, the cost and schedule for the Lee project are far from "fixed" or "guaranteed." In fact, based on historical experience and current trends, both the cost and schedule are likely to shift, perhaps dramatically. Requiring ratepayers to pay financing costs during the construction of this substantial and uncertain project would shift all of the project's risk onto captive ratepayers, who are already subject to a continuing trend of unrelated but significant rate increases. Duke's

[12] A 2010 *Energy Policy* article by Arnulf Grubler found negative learning in the experience of the French nuclear program. See Grubler, Arnulf. "The Cost of the French nuclear scale-up: A case of negative learning by doing." *Energy Policy.*38 (2010) 5174-5188.

shareholders, in contrast, would stand to make a healthy profit regardless of the success of the project.

Given these facts, we find that Duke's ratepayers will be poorly served if North Carolina adopts early ratepayer financing under nuclear Construction Work in Progress legislation.

2. Introduction

Until very recently, a new nuclear power plant had not been ordered in the United States since the late 1970s. Now, after over 30 years of inactivity, two projects are currently under construction—the Vogtle project in Georgia and the VC Summer project in South Carolina.[13] Both projects are in states that allow the companies to recover financing costs from ratepayers as the plants are being built.

The William States Lee III nuclear energy project, also in South Carolina, is not yet approved. The project consists of two reactor units (Unit 1 and Unit 2), which Duke proposes to build at a site in Cherokee County, South Carolina. This is the same site where, decades ago, Duke proposed to build the Cherokee Nuclear Station; and ultimately abandoned it in 1983, after spending $600 million (in 1983 dollars) or $1.3 billion in 2012 dollars.[14]

Duke is now advocating for legislation in North Carolina, which would compel its electricity customers in the state to carry the financing risks associated with its proposed Lee nuclear reactors. (Currently, North Carolina has a weaker version of this CWIP recovery mechanism, allowing Duke Energy to petition the commission for recovery, but with no guarantee of success.) The draft legislation would allow Duke to recover and earn a return on construction financing costs annually during construction of the proposed plant. In addition, the proposed legislation would guarantee that Duke would be able to recover approved construction costs even if the plant is never completed. Table 1 below highlights key characteristics of the Lee project. Characteristics of SCE&G's proposed VC Summer nuclear facility are also included, for two reasons:

1) The VC Summer project shares several key physical and financial characteristics with the Lee project, and is used as a basis for comparative analysis in this study; and

2) Duke is considering purchasing up to 10% of the VC Summer project from Santee Cooper, which has implications for North Carolina ratepayers should the state's legislature adopt early financing cost recovery legislation. This ownership fraction may be as high as 20% as a result of the Duke-Progress merger.

[13] With these two approved applications, there are now ten filed applications before the Nuclear Regulatory Commission (NRC) to build new nuclear plants or expand existing U.S. plants.[13]

[14] Duke Energy Carolinas, LLC.. *Duke Energy Carolinas, LLC. Response to Department of Energy Federal Loan Guarantee Application Part I and II- Section B Project Description I-B-I and II-B-I.* Page B-29

Table 1. Similarities and Differences between the Lee and VC Summer Projects

Characteristic	Duke Energy (Lee)	SCE&G (VC Summer)
Reactor Type	AP1000	AP1000
Number of Units	Two	Two
Estimated Capacity (MW)	2,234	2,234
Greenfield Site	Yes*	No
Expansion of Existing Site	Yes*	Yes
Expected First Unit Completion Year	2022	2017
Expected Second Unit Completion Year	2024	2019
Federal Loan Guarantee	No	No
Early Financing Cost Recovery	Seeking	Yes
Ongoing Reporting to State Commission	Not Applicable	Yes
Latest Overnight Cost Estimate (2010$)[15]	$13.1 billion	$8.5 billion
Company Ownership Share	100%	55%
Company Share of Overnight Cost Estimate (2010$)[16]	$13.1 billion	$4.7 billion

As an interesting aside, when Duke abandoned plans to develop the Cherokee plant, the Company indicated that reduced load growth and high interest rates forced the Company to abandon its plans.[17] Although Duke was able to recover its investment in the Cherokee plant, it did not recovery financing costs or a return on its investments. In 2012, Duke is pressing North Carolina to pass the proposed Construction Work in Progress recovery mechanism. Should North Carolina pass the proposed nuclear financing legislation, Duke would likely be able to pass on costs to ratepayers, including financing costs, even if it ultimately abandons plans to develop the Lee plant.

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15 The Lee project can be considered both a greenfield project and an expansion of an existing site, given that the foundation for Duke's abandoned Cherokee Nuclear Station was built there, but the plant never came close to being operational. Although some infrastructure from the abandoned site may be utilized, it is not clear how much new infrastructure would be needed for the proposed plant.

16 The latest company overnight cost estimates exclude construction financing costs and inflation.

17 Duke Energy Carolinas, LLC.. *Duke Energy Carolinas, LLC. Response to Department of Energy Federal Loan Guarantee Application Part I and II- Section B Project Description I-B-I and II-B-I.* Page B-29.

3. Uncertain Project Costs

Duke Estimates of Project Costs

When the Lee project was initially proposed in 2005, before the recession, to meet then-anticipated growth in electricity demand, Duke estimated the project would cost $2 billion, and would be completed in 2015. In 2007, Duke significantly increased its cost estimate for this project, to $6 billion. This estimate was raised again, in 2008, to $11 billion; and again, in 2011, to $13.1 billion (in 2010$, excluding financing costs). In Duke's 2012 IRP, the anticipated completion date has slipped to 2022 for Lee 1 and 2024 for Lee 2.[18]

Duke has not publicly changed its cost and schedule estimates since 2008. (The 2011 estimate of $13.1 billion has not been publicly announced by Duke; this estimate was provided as part of a response to NCUC staff in the 2011 Duke base rate case.[19]) However, given recent press announcements about delays with the other AP1000s units, we anticipate that the final project cost and schedule are far from certain.[20] The following exhibit outlines some of the benchmarks associated with the Lee project to date:

[18] Details of the $11 billion cost estimate are from Jamil, Dhiaa. *Duke Energy Nuclear Informational Session with Analysts*. Presentation June 3, 2009. Slide 11. The $13.1 billion cost estimate comes from documents provided as part of Duke's 2011 base rate case filed under NCUC Docket E-7 Sub 989.

[19] NCUC Docket E-7 Sub 989, Response to E-1 Item 41. July 1, 2011.

[20] Recent testimony from the Vogtle and VC Summer projects has already identified delays just resulting from site work issues. On April 11, 2012, Georgia Power made a request to the NRC to continue with concrete foundation work even though the base concrete foundation was found to be out of the license specification. In addition, the NRC has found that the rebar for the plant's foundation did not meet design specifications.

Table 2. Chronology of Events for Duke Energy: Lee 1 and 2 and Company Cost Estimates

Year	Month	Event	Completion Date	Overnight Cost Estimate ($billions) (current$)	Overnight Cost Estimate ($billions) (2010$)	Note
2005	Oct.	Duke announces plans to build nuclear plant	2015	$2	$2.2	1.
2007	Dec.	Duke files NRC application	2015	$5-6	$5.2-6.2	2.
2008	Nov.	Cost estimate raised for Lee 1 and 2	2016, 2018	$11	$11.2	3. 4.
2009	Feb.	Delay in completion date	2018			5.
2011	June	Change in cost estimate and schedule	2021, 2023	$13.1	$13.1	6.
2011	Sept.					7.
2012	Sept.	Change in schedule	2022,2024			8.

Notes: We understand that the cost estimates presented in the cited materials reflect overnight costs in current year dollars of the date of the estimate.

1. www.bizjournals.com/charlotte/stories/2005/10/24/daily23.html?jst=b_ln_hl
2. www.bizjournals.com/triangle/stories/2007/12/10/daily38.html
3. www.world-nuclear-news.org/NN-Duke_raises_cost_estimate_for_Lee_plant-0711084.html
4. http://pbadupws.nrc.gov/docs/ML0831/ML083110471.pdf
5. www.duke-energy.com/pdfs/DukeEnergy10K.pdf, page 80.
6. North Carolina Utilities Commission, Docket No E-7, Sub 989.Response to E-1 Item 41. Data presented for Test year ending December 31, 2010.
7. Duke Energy Carolinas. *2011 Integrated Resource Plan.* Page 9.
8. Duke Energy Carolinas. *2012 Integrated Resource Plan.* Page 11.

From 2007 to 2011, the estimated cost of this project has doubled in real terms, from $6 billion to $13.1 billion (2010$). The completion date has moved ten years, from 2015 to 2024.

These trends, alone, point to major risks for ratepayers. However, the lack of transparency surrounding this project exposes Duke's ratepayers to *even greater* risk, by hindering independent analyses of the Company's cost and schedule assumptions.

While detailed information about the project's estimated cost and schedule is provided to the North Carolina Utilities Commission (NCUC) in Duke's Integrated Resource Plan, the company has classified almost all of this cost and schedule information as trade secret. Additional project information in a Duke pre-development cost docket has also been classified as confidential.

In 2011, Duke sought $459 million in cumulative pre-development costs for the Lee project (these costs are separate from the financing costs that would be recovered through "early financing cost recovery" legislation). However, the NCUC—which *has* reviewed Duke's cost and schedule information for the Lee project—only approved $292 million of that amount, citing that the Lee project :1) lacked approval from the NRC, 2) had no timeline, and 3) did not have the benefit of the early financing cost recovery legislation in North Carolina.[21]

[21] North Carolina Utilities Commission. August 5, 2011 Order in Docket E-7 Sub 819. Page 22.

Levelized Cost Estimates: A Plausible Range

Given the high level of uncertainty associated with Duke's estimates of project costs, this study conducts a levelized cost analysis in order to provide ratepayers and policymakers with a useful and plausible range of costs to reference in considering this project.

In this section, we calculate the levelized cost of energy from the Lee project for three different scenarios. It is reasonable to think of levelized costs as a range rather than single point values, since uncertainties exist in both investment and operating costs for different resources and technologies; differences in site-specific factors also influence costs for individual projects.

To identify a range of electricity costs from the Lee project, we first determined the low end of the range by using the latest project costs reported by Duke. We developed a high-end cost estimate for the project based on historical precedent (i.e., the project's increase in estimated cost between 2007 and 2010). Historical information provides a reasonable, if uncertain, proxy for future nuclear construction costs associated with a new, unproven design.[22]

We then convert these costs into a levelized production cost of electricity, representing all the fixed and variable costs. Our costs for this project do not include nuclear waste disposal and decommissioning costs, which constitute another, albeit uncertain, cost component of nuclear power.

According to our analysis, the busbar levelized cost range for Lee 1 and 2 is between $107 and $194 per MWh (in 2010$).[23] The range in our cost estimate reflects the uncertainty associated with developing complex projects with the AP1000 reactor in the United States.

- **Low estimate:** At the low end, we have taken Duke's current overnight project cost of $13.1 billion (2010$) and have included financing costs to estimate a 2024 completion year cost of $20.7 billion (2024$).[24] Restating our low cost estimate into a levelized cost of electricity results in a value of $107 per MWh (2010$).
- **High estimate:** In the absence of well-documented, publically available information from the company on which to base our analysis, we have based our high estimate for the proposed project on historical precedent—the increase in the project's overnight cost from $6 billion in 2007 to $13.1 billion in 2010 (equivalent to an 103% increase in 2010$). This results in a high-cost estimate of $194 per MWh, or $41.5 billion (2024$) for the project. Our high-cost estimate for this project does not necessarily imply certainty in future project costs, only a possible outcome that should be considered given the lack of well-documented, publically available information from the company. The final cost of the next generation of nuclear plants is simply unknown.
- **Mid-range estimate:** Our mid-range cost estimate for the project is one half of our high-estimate cost trajectory, or a 50% increase, resulting in a levelized cost of electricity

[22] Kessides, I. Nuclear power: Understanding the economic risks and uncertainties. Energy Policy. 38(2010) 3849-3864. As noted by the author, "There is widespread agreement that the best predictors for the future costs of nuclear plants are based on actual experience rather than detailed engineering cost models and estimates."

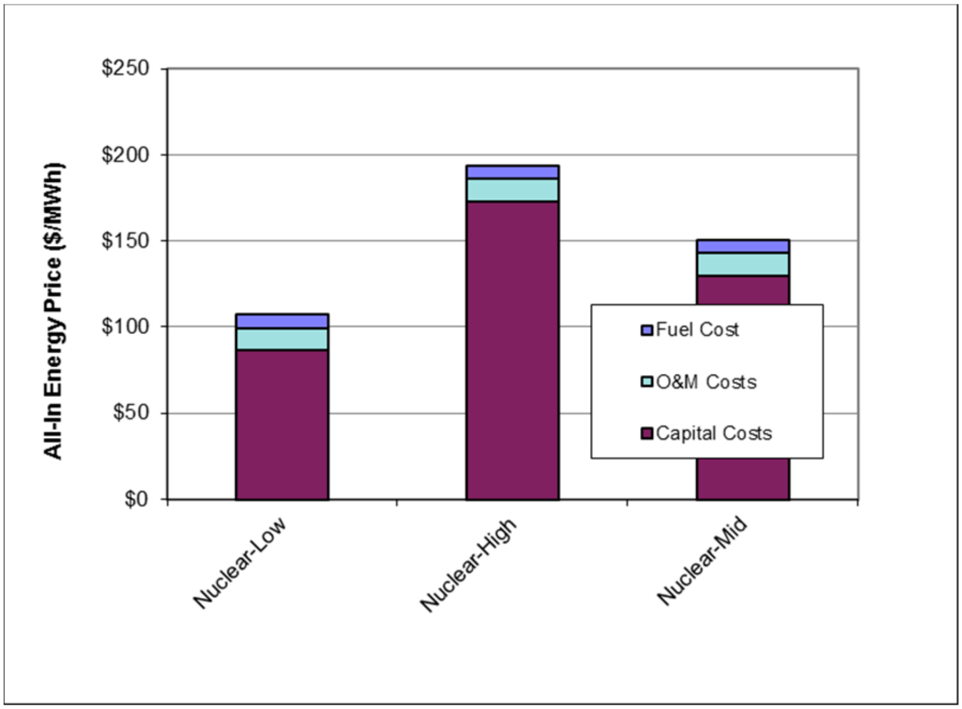
[23] The busbar cost of electricity represents the cost of producing electricity before entering the grid.

[24] Financing costs over the construction period (5-10 years) adds 20%-35% to the overnight cost estimate.

estimate of $151 per MWh, or a project cost estimate of $32.7 billion (2024$). An internal Duke email has suggested that a 40 to 50% increase is reasonable.[25]

Our estimated levelized costs of electricity for each scenario, broken out by major cost components, are summarized in the figure below for the proposed Lee plant.

Figure 1. Lee Levelized Cost Components: Low, High, and Mid Cost Estimates



To put our cost estimates into perspective, we roughly estimate that the current residential rates are about $129/MWh (12.9¢/kWh), of which energy represents $92 per MWh (9.2¢/kWh). All three of our cost estimates for energy from the Lee plant are higher than the energy costs embedded in Duke's current rates that are themselves an increase from 2009 and 2011 rate cases. Furthermore, the projected Lee impacts do not account for rate impacts as a result of Cliffside Unit 6, Buck Combined Cycle Plant, and the Dan River Combined Cycle plant as shown in Appendix A. Moreover, our mid and high cost estimates are higher than the *total* current rate for Duke residential customers. This simplified comparison suggests that, regardless of our cost estimate, the proposed cost of the Lee project will result in an increase in electricity rates for Duke's residential ratepayers.

[25] North Carolina Utilities Commission. August 5, 2011 Order in Docket E-7 Sub 819. Page 7. Under cross-examination, Duke CEO Jim Rogers disagreed with the internal assessment.

4. Cost Recovery Mechanism: Shifting Risks to Ratepayers

Ultimately, the risks associated with the Lee project—including the lack of transparency, and the likelihood of cost escalation and regulatory and construction delays—are likely to result in very high costs to ratepayers. As mentioned earlier in this study, the North Carolina legislature is considering requiring ratepayers in North Carolina to fund this expensive nuclear energy project annually and long before it begins producing energy, whether or not it ever does.

Duke is not without precedent in abandoning nuclear projects. In fact, the proposed site of the Lee project is the same site where, decades ago, Duke proposed to build the Cherokee Nuclear Station. After spending $600 million in 1983 dollars (equivalent to almost $1.3 billion today), Duke abandoned its plans to develop this nuclear facility in 1983.

If North Carolina adopts early financing cost recovery legislation, ratepayers will be on the hook for just this sort of risk. Under the proposed law, Duke would be able to recover the financing costs associated with the Lee project—whether or not the proposed nuclear plant is completed, and no matter how much it costs in the end. Under this proposed law, ratepayers, not the company shareholders, would bear the financial risk of the proposed plant.

Potential Rate and Bill Impacts on Duke Ratepayers

Duke has not publicly presented analyses calculating potential costs to ratepayers associated with just the Lee project.[26] Since Duke has not provided bill impact analyses specific to the Lee project, we have calculated (at a high level) rate and bill impacts associated with the proposed plant shown in Figure 2 below. This analysis is illustrative and independent of future rate changes. Our analysis compares the impacts of the project to both the current 2012 and 2009 electric rates.[27] The assumptions used in our analysis are described in detail Appendix C.

[26] Our rate and bill impact analysis focuses solely on the impact associated with the proposed Lee plant. Other investments that would affect rates are not included in this analysis.
[27] As a point of further reference, we have included Duke's 2009 residential rates.

Figure 2. Illustrative Residential Monthly Electric Rate and Annual Electric Bill Impact of Proposed Lee Plant Cost Scenarios Independent of Other Rate or Bill Impacts

	Monthly Rate Impact ($/kWh)			Annual Bill ($)		
Year	Low Estimate	Mid Estimate	High Estimate	Low Estimate	Mid Estimate	High Estimate
2009	0.086	0.086	0.086	$1,030	$1,030	$1,030
2012	0.093	0.093	0.093	$1,115	$1,115	$1,115
2013	0.093	0.093	0.093	$1,119	$1,119	$1,119
2014	0.094	0.094	0.094	$1,122	$1,124	$1,126
2015	0.095	0.095	0.096	$1,134	$1,142	$1,149
2016	0.096	0.098	0.099	$1,154	$1,172	$1,189
2017	0.98	0.101	0.103	$1,179	$1,209	$1,239
2018	0.101	0.104	0.108	$1,206	$1,250	$1,294
2019	0.103	0.108	0.113	$1,236	$1,294	$1,352
2020	0.105	0.112	0.118	$1,265	$1,339	$1,412
2021	0.108	0.115	0.122	$1,292	$1,378	$1,465
2022	0.109	0.117	0.125	$1,312	$1,408	$1,504
% Change from 2012	18%	26%	35%	18%	26%	35%
CAGR from 2012	1.6%	2.4%	3.0%	1.6%	2.4%	3.0%
% Change from 2009	27%	37%	46%	27%	37%	46%

Notes:

- **Based on Duke's average monthly residential consumption of 1,000 kWh**
- **Inputs from Duke Energy Carolinas, NCUC Docket E-7 Sub 989**
- **All other factors affecting future and current rates held constant**
- **CAGR Compound Annual Growth Rate**

Under the low estimate scenario, we have calculated that the resulting residential rate and bill impact in 2022 would be an increase of 18%, from current 2012 residential rates, for an average residential customer using 1,000 kWh per month. This would translate into an increase in annual electricity bills of approximately $193 from just the proposed Lee plant (the difference between a $1,312 electric bill in 2022, in the table above, and a $1,115 electric bill in 2012). As we have noted earlier, we do not anticipate that the costs of the Lee plant will meet our low estimate. We believe that our mid and high estimates represent more realistic estimates of the uncertain costs associated with the proposed project.

Our mid-case scenario would increase bills and rates by 26% by 2022 compared to current residential rates. This results in an increase in the annual electricity bill from 2024 to 2012 by approximately $293. Our high estimate, which does not represent an upper bound for potential impacts, would result in a bill and rate impact increase of 46% compared to current electricity bills. This would increase annual bills by $389.

As detailed in Appendix A, Overall Duke rates will continue to climb with the inclusion of the planned Cliffside Unit 6, Buck Combined Cycle, and Dan River Combined Cycle plants, amounting to $3.56 billion in capital projects. The increase in rates from those three plants is likely to be partially offset by the planned retirement of approximately 2,000 MW of older, fossil units. While we cannot know precisely the net impact without knowing the operating costs associated with either the new units or the retiring units, Duke has indicated that as of March 31, 2012, $192 million remained on the Company's balance sheet for their retired and yet to retire units, and that the Company will seek to recover the $192 million of unrecovered balances. Thus ratepayers may expect to continue paying for almost $200 million in residual costs for the retired plants in addition to the costs of the new and repowered plants, If the legislature approves annual CWIP and the Lee project goes forward, these costs will be compounded with substantial financing costs for a plant that will not come on line for several years into the future,

In addition, our analysis does not include the impact of the Cliffside Unit 6 coal burning unit, which is expected to be completed in 2012. At this time, Duke has not filed a rate case to reflect the inclusion of this $1.8 billion project into the Company's rates. Applying the current Duke rate of return of 8.11% to the expected cost of $1.8 billion gives an annual cost recovery of $146 million, which represents about a 3% increase in the current revenue requirements.[28] When Duke seeks to recover the cost of Cliffside Unit 6, the precise impact will be known. This is independent of and in addition to any impacts on Duke ratepayers from a future Lee plant.

Industry Trends in Nuclear Plant Costs

In this section, we highlight bill impacts reported by other utilities building or proposing to build new nuclear reactors in order to demonstrate trends in nuclear development impacts on ratepayers. We include announcements from SCE&G's VC Summer project in South Carolina, Georgia Power's Vogtle project in Georgia, and Progress Energy's Levy project in Florida.

VC Summer

Given the lack of detailed cash flow and rate information from SCE&G, our analysis of the bill impacts associated with the VC Summer project is based on current SCE&G rates, SCE&G press releases, and the current construction schedule. SCE&G has announced that rates associated with financing costs for VC Summer will "average a little more than 2 percent annually through 2019, but will vary year to year based on actual construction expenditures incurred."[29] The annual rate increase assumed in our analysis is based on the 2.3% VC Summer rate increase approved by the South Carolina Public Service Commission (SC PSC) in October 2010 and the 2.4% increase approved in September 2011. Our calculations of SCE&G's announced annual increases suggest that SCE&G's current cost estimate of $11 billion for VC Summer will add at least $322 per year to the bill of a typical SCE&G residential customer using 1,000 kWh per month by 2019.

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[28] The approved rate of return is based on Duke's return on equity of 10.3% and cost of debt of 5.4%. Duke's equity and debt fractions are 53% and 47% respectively.

[29] SCE&G. *SCE&G Files for Rate Adjustment Under Base Load Review Act.* Press release on May 21, 2011.

Vogtle and Levy

From our 2011 report (*Big Risks, Better Alternatives: An Examination of Two Nuclear Energy Projects in the U.S.),* we also include the bill impacts from Vogtle 3 and 4 and Levy 1 and 2 as announced by Georgia Power and Progress Energy, respectively.

- Based on Georgia Power's current cost estimate of $14 billion: By 2018, the Vogtle project will add at least $120 per year to the bill of a Georgia Power residential customer using 1,000 kWh per month.[30]
- Based on Progress Energy's cost estimate of $22.5 billion: By 2021, the Levy project will add at least $718 per year to the bill of a typical Progress Energy residential customer using 1,100 kWh per month.[31] These estimates are now too low, since Progress has recently announced the cost of Levy 1 and 2 has increased to $24 billion and that Unit 1 would be delayed until 2024.[32]

Progress Energy, the owner of the Levy project, is the only company that has made portions of its cost analyses public; the other companies have redacted all cost analyses information as being "confidential." Should these projects come in at higher costs than anticipated by their developers, ratepayers will pay a correspondingly larger amount. And if they are cancelled, ratepayers will have been paying for something from which neither they nor their descendants will receive any benefit.

Allocation of Cost Recovery Risk: Shareholders and Ratepayers

Proponents of nuclear early cost recovery argue that pre-paying financing costs before actual completion reduces overall project costs. This argument is not new. In the late 1970's and early 1980's, academic and industry research examined the advantages and disadvantages of Construction Work in Progress.[33]

Under traditional ratemaking the construction and financing costs accrue on the company's balance sheet as construction progresses, at the utility's (generally favorable) cost of capital. During this period, the company, and ultimately shareholders and bondholders, bear the risk of financing the project. Once completed and approved, a company then passes on the accrued balance into rates. The approach has the disadvantage in that ratepayers would see a large increase in rates or "rate shock" as large capital projects, such as a nuclear power plant, become incorporated into rates.

Under an early recovery scenario, the financing costs are approved and passed into rates on an annual basis, so that ratepayers would see a gradual increase in rates as the project is under construction. The utility effectively covers the financing costs of the project with an interest-free

[30] Georgia Power. Available at http://www.southerncompany.com/nuclearenergy/costs.aspx. Accessed April 12, 2012. We have not included the impact of the $800 million in cost overruns currently in dispute between the owners and contractors of the project.

[31] Progress Energy Florida. Supplemental Response to Office of Public Counsel's Third Set of Interrogatories (No.47) dated July 7, 2010 in Docket 100009-EI.

[32] http://www.tampabay.com/news/business/energy/progress-energy-raises-price-tag-delays-start-date-of-levy-nuclear-plant/1227830. Accessed May 1, 2012.

[33] Comptroller General of the United States. *Construction Work in Progress Issue Needs Improved Regulatory Response for Utilities and Consumers.* EMD-80-75. June 23, 1980.

loan from ratepayers, instead of relying on capital markets for this portion of project costs. When completed, the Company would then seek to recover the project costs into rates, but overall project costs would appear to have been reduced since the financing costs would have already been borne by ratepayers; thus the rate shock would be less dramatic compared to traditional ratemaking, but the total cost to consumers would be as great or greater. Under an early recovery scenario, ratepayers would also be required to absorb rate increases if there are project delays and/or project cost increases.

From a company's perspective, both scenarios will result in recovery of the project costs. However, under the traditional recovery scenario, the accrued returns associated with the financing costs are treated as an asset from a balance sheet perspective, while the Company still pays for interest costs during construction. The company also carries a larger balance that may be at risk in case of project failure under traditional ratemaking. Because there is only the expectation of future recovery from ratepayers, and not actual cash that can be used by utility, the financial community generally views the traditional treatment as a lower quality asset, and this may impact the credit rating of the utility.

5. Findings & Recommendations

This analysis indicates that proposed legislation in North Carolina, which would provide Duke with early recovery of financing costs for the proposed Lee plant, would expose ratepayers to a number of significant risks. Moreover, a proposed Lee nuclear project would expose Duke ratepayers to project overrun risk that could be significant. These risks will only increase for Duke ratepayers if the company purchases an ownership fraction of the VC Summer project, or if it acquires an ownership fraction through a proposed merger with Progress Energy Carolinas.

Key findings identified in our analysis include the following:

- There is significant uncertainty regarding 1) if the Lee nuclear project will be completed, 2) when it will be completed, and 3) what the final project costs will be for the plant if and when complete. Detailed information about the project's schedule and the cost projections have been marked confidential by Duke, hindering independent analysis of the company's claims. Our analysis suggests that the final project cost, while far from certain, is likely to be much higher than the current estimate.
- Our low estimate of the likely levelized cost of energy from the project is $107 per MWh (10.7 cents/kWh), based Duke's current completion schedule of 2022 for Lee 1 and 2024 for Lee 2. Our low estimate translates into a total project cost of $20.7 billion (2024$).
- Our high estimate of the levelized cost of energy from the project is $194 per MWh (19.4 cents/kWh), based on a percentage of the cost increases announced by Duke for Lee 1 and 2 between 2007 and 2011. This translates to a total project cost of $41.5 billion (2024$).
- Our mid-range analysis of the levelized cost for the project is $151 per MWh (15.1 cents/kWh), based on a percentage of the cost increases announced by Duke for Lee 1 and 2 between 2007 and 2011. This translates to a total project cost of $31.1 billion (2024$).
- Our calculations suggest that Duke residential rate payers will be paying $197 more per year by 2022 as a result of paying financing costs for the proposed plant under our low estimate. Under our high estimate, which does not represent an upper bound, Duke rate payers would pay $389 more per year by 2022 to finance the construction cost of the proposed plant. These calculated bill impacts are independent of any other changes to Duke's rate base.
- Duke is not without precedent in abandoning nuclear projects. If North Carolina adopts early financing cost recovery legislation, ratepayers may be responsible for new nuclear reactor costs no matter how much they increase, and even if the project is not completed.
- Requiring ratepayers to pay financing costs during construction of the plant when the final cost and completion schedule are unknown shifts the project risk onto ratepayers instead of shareholders. Doing so could cost ratepayers more than under traditional financing.

Duke's ratepayers are already subject to much higher rates than in the past as the result of significant rate increases approved in the company's 2009 and 2011 rate cases. With or without the Lee plant, they may look forward to more rate increases in the future associated with new capital projects as detailed in Appendix A, and they are likely to continue paying for plants with unrecovered balances even as a number of these are taken out of service. Thus, if the Lee project moves forward and the company is awarded annual Construction Work in Progress financing, ratepayers may expect to be paying simultaneously for older resources that are no longer used and useful, new capital projects for conventional resources, and high financing costs for a nuclear plant that will not produce energy for many years into the future, if at all.

Given these findings, we strongly recommend that North Carolina avoid adopting legislation that shifts the financing risk of proposed nuclear energy projects from company shareholders to captive ratepayers.

Appendix A: Duke Energy Planned Plant Additions and Retirements

The following table details Duke's completed or announced fossil plant additions and retirements.

Planned Plant Additions				
Project	**Cost ($millions)**	**Capacity (MW)**	**Year in Service**	**Notes**
Cliffside Unit 6	$2,200	825	2012	1
Buck Combined Cycle Plant	$675	620	2011	2
Dan River Combined Cycle	$710	620	2012	3
Lee Steam Station Conversion		170	2015	4
Total	**$3,585**	**2,235**		
Planned Plant Retirements				
Project	**Capacity Factor**	**Capacity (MW)**	**Year Retired**	**Notes**
Buck 3	6.7%	75	2011	5
Buck 4	7.7%	38		6,7,8,9
Cliffside 1	0.0%	38	2011	
Cliffside 2	0.0%	38		
Cliffside 3	0.0%	61		
Cliffside 4	0.0%	38		
Dan River 1	5.8%	67	2012	
Dan River 2	6.2%	67		
Dan River 3	6.5%	142		
Buzzard Roost 6C - 15C	0.0%	196	2012	
Riverbend 8C - 11C	0.0%	64	2012	
Buck CT	0.0%	62	2012	
Dan River 4C-6C	0.0%	48	2012	
Riverbend 4	10.3%	94	2015	
Riverbend 5	10.1%	94		
Riverbend 6	15.4%	133		
Riverbend 7	15.7%	133		
Buck 5	18.8%	128	2015	
Buck 6	16.4%	128		
Lee 1	10.8%	100	2014	
Lee 2	11.2%	100		
Lee 3	16.8%	170		
Weighted Average/Total	**9.0%**	**2,014**		

Notes

1 http://www.duke-energy.com/pdfs/1Q-2012-DEC-Combined-10Q.PDF
2 http://www.duke-energy.com/investors/financials-sec-filings.asp
3 http://www.duke-energy.com/pdfs/1Q-2012-DEC-Combined-10Q.PDF
4 Duke Energy Carolinas LLC 2011 Integrated Resource Plan, (September 1, 2012) p. 16
5 Buck 3&4 retired in 2011; Capacity factors taken from Duke Energy's "Monthly Fuel Report" dated July 2011 in NCUC Docket E-7 Sub 981
6 Capacity factor data taken from Duke Energy's "Monthly Fuel Report" dated July 2012 in NCUC Docket E-7 Sub 1003
7 http://www.platts.com/RSSFeedDetailedNews/RSSFeed/ElectricPower/3896790
8 http://www.southernenvironment.org/newsroom/press_releases/agreement_cuts_pollution_
http://sustainabilityreport.duke-energy.com/environmental-footprint/positioning-our-coal-fleet-
9 Duke notes that 1,356 MW of planned retired coal units have an unrecovered plant balance of $192 million as of March 31, 2012. Duke intends to seek recovery of these plant balances http://www.duke-energy.com/pdfs/1Q-2012-DEC-Combined-10Q.PDF

Duke's 2011 and 2012 IRP, the Company includes 2,235 MW of new fossil plants primarily through the addition of Cliffside Unit 6, Buck Combined Cycle plant, and the Dan River Combined Cycle plant.[34] We also include the planned conversion of the Lee Steam Station, although we have not seen an estimate of costs associated with this conversion project. Our table includes estimated costs based on Duke Energy's public filings to the Securities Exchange Commission. At this time, we do not know how Duke will incorporate the final plant addition costs into its rate base, since the Company has not yet filed to seek recovery on these new plants. As a result, these costs will be in addition to our rate impact estimates associated with the proposed Lee plant.[35]

While we anticipate that Duke rates will increase as a result of $3.6 billion in plant additions, some of the rate increase will likely be offset by the reduction in operating expenses as a result of announced plant retirements of 2,014 MW. Of this, 1,600 MW of retirements are the result of the Cliffside Unit 6 settlement.[36] Our table also includes capacity factors for the previous twelve months for plants scheduled for retirement.[37] The capacity factors provide a snapshot to the utilization of these plants. As shown in the table, these plants are now low capacity plants that have operated infrequently in the last twelve months. Thus, we are uncertain how much ratepayers will save through reduced operating expenses of these plants as they are retired.

Another consideration associated with the retirement of the listed plants is that not all of the plants are fully depreciated. Duke's 2012 first quarter filing to the Securities and Exchange Commission notes that there is $192 million of unrecovered plant balances associated with 1,356 MW of plants scheduled for retirement.[38] The Company notes: "Duke Energy continues to evaluate the potential need to retire these coal-fired generating facilities earlier than the current estimated useful lives, and plans to seek regulatory recovery for amounts that would not be otherwise recovered when any of these assets are retired."[39] We anticipate that Duke will seek to recover those plant balances even as it retires some of its older coal plants.

[34] Duke Energy Carolinas. 2011 Integrated Resource Plan, dated September 1, 2011. Page 11. Duke's 2012 IRP
[35] Duke's 2012 IRP also includes approximately 3,850 MW of new unidentified capacity between 2016 and 2032.
[36] Power Engineering, "Duke Energy to retire more than 1,600 MW of coal-fired capacity". http://www.power-eng.com/articles/2012/01/duke-energy-to-retire-more-than-1600-mw-of-coal-fired-capacity.html
[37] Capacity factor data for the previous twelve months taken from Duke's monthly fuel reports provided to the North Carolina Utilities Commission.
[38] Duke Energy. 2012 First Quarter 10Q. page 38.
[39] Duke Energy. 2012 First Quarter 10Q. page 38.

Appendix B: Nuclear Costs and Risks

Historical Costs

The nuclear industry has had a very poor track record in predicting project construction costs and avoiding cost overruns. In a report to Congress, the Department of Energy provided a table of the actual costs of 75 of the existing nuclear power plants in the U.S. (out of 105 total) that exceeded the initially estimated costs.[40] (Exhibit A-1) this table shows that, on average, these projects experienced a cost overrun of 207% as compared to utilities' projections.

Exhibit A-1. Comparison of Historical Projected and Actual Nuclear Power Plant Construction Costs in the United States

Construction Starts		Average Overnight Costs[a]		
Year Initiated	Number of Plants[b]	Utilities' Projections (Thousands of dollars per MW)	Actual (Thousands of dollars per MW)	Overrun (Percent)
1966 to 1967	11	612	1,279	109
1968 to 1969	26	741	2,180	194
1970 to 1971	12	829	2889	248
1972 to 1973	7	1,220	3,882	218
1974 to 1975	14	1,263	4,817	281
1976 to 1977	5	1,630	4,377	169
Overall Average	**13**	**938**	**2,959**	**207**

Source: Congressional Budget Office (CBO) based on data from Energy Information Administration, An Analysis of Nuclear Power Plant Construction Costs, Technical Report DOE/EIA-0485 (January 1, 1986).

Notes: Electricity-generating capacity is measured in megawatts (MW); the electrical power generated by that capacity is measured in megawatt hours (MWh). During a full hour of operation, 1 MW of capacity produces 1 MWh of electricity, which can power roughly 800 average households.
The data underlying CBO's analysis include only plants on which construction was begun after 1965 and completed by 1986.
Data are expressed in 1982 dollars and adjusted to 2006 dollars using the Bureau of Economic Analysis's price index for private fixed investment in electricity-generating structures. Averages are weighted by the number of plants.

a. Overnight construction costs do not include financing charges.
b. In this study, a nuclear power plant is defined as having one reactor. (For example, if a utility built two reactors at the same site, that configuration would be considered two additional power plants.)

Proponents of a nuclear resurgence argue that the recently approved AP1000 reactor design is more standardized than predecessors, and thus will not be exposed to the same cost and performance uncertainty as prior nuclear projects in the United States. However, recent experience of the nuclear energy industry is calling these assumptions into question.[41]

40 CBO, as referenced in Exhibit A-1.
41 *Special Report: Nuclear Energy.* The Economist. March 10, 2012

Modern-Day Cost Overruns

Nuclear projects in the United States, Finland, and France are experiencing significant delays and cost overruns. The 2011 Fukushima Dai-Ichi plant disaster has raised even broader questions about nuclear safety and associated costs and risks; following the crisis in Japan, Germany announced that it will shut down all 17 of its nuclear reactors by 2022, while Switzerland and Italy have abandoned plans to build new reactors.

Following are examples of modern-day nuclear projects experiencing delays and cost overruns:

Levy 1 and 2

In the United States, the proposed Levy plant in Florida has been plagued with delays and cost escalation, and the company has yet to receive approval to begin construction. [42] An additional risk specific to Levy 1 and 2 that may also extend to Lee 1 and 2 has been the NRC's delay in reviewing its application as a result of the Fukishima Da-ichi disaster.[43]

Vogtle 3 and 4

In Georgia, Georgia Power has not provided a detailed, publicly available cost estimate for Vogtle 3 and 4 since the project was announced in 2006.[44] Recently, Georgia Power announced a delay in Unit 3 by six months (from April 2016 to November 2016). There has also been news of disputed cost overruns of $800 million.[45]

Experience at the proposed Vogtle 3 and 4 nuclear reactors highlights some of the risks that may be shouldered by Duke ratepayers in the future, should North Carolina adopt early cost recovery legislation. These risks have been expressed in qualitative terms in filings made by the Georgia Independent Construction Monitor (ICM). The ICM was hired by the Georgia PSC, using Georgia Power's money, to provide semi-annual progress reports on the Vogtle project.

In December of 2011, testimony from the ICM identified unresolved issues from its previous construction monitoring report that include the following:[46]

- Design and fabrication of modules and sub-modules at the Shaw Modular Solutions ("SMS") facility as required to meet the project schedule; and
- Production of Vogtle-specific Certified for Construction ("CFC") construction packages as required to meet the project schedule.

Both of these "unresolved issues" impact the project schedule, indicating a reasonable likelihood of costly delays. More recent issues at the Vogtle plant include: an announcement that the rebar in the concrete basemat do not meet the design specifications, and that the concrete foundation for

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42 Chang M, White D, Hausman E, Hughes N, Biewald B. *Big Risks, Better Alternatives: An Examination of Two Nuclear Energy Projects in the U.S*. October 2011.

[43] Wingfield, Brian., Johnsson, Julie. *Progress Energy Reactor Review May be Delayed, NRC Chief Says.* Bloomberg News. March 31, 2012. Available at http://www.businessweek.com/news/2012-03-31/progress-energy-reactor-review-may-be-delayed-nrc-chief-says. Accessed April 13, 2012.

[44] Chang. (2011).

[45] Georgia Public Service Commission. *Plant Vogtle Units 3 & 4 Sixth Semi-Annual Construction Monitoring Report.* February 2012. Docket 29849.

[46] Jacobs, William. Direct Testimony and Exhibits In the Matter of Georgia Power Company's Fifth Semi-Annual Vogtle Construction Monitoring Report." Docket 29849, filed December 2, 2011. Page 6.

the reactor does not meet specifications.[47] [48] While the lessons learned at Vogtle may ultimately provide some benefit to Duke, the "Vogtle experience" also highlights the complexity of building new reactors—even when those reactors have a more "standard" design.

Flamanville 3, South Texas Project, and Olkiluoto

A 2009 Citigroup equity research report cited several cost overruns and delays in the current generation of nuclear power plants. We highlight some examples of cost escalation trends from the report, along with subsequent developments, which confirm that trend:[49]

- Towards the end of 2008, the French company EdF increased its cost assumptions for the Flamanville 3 reactor unit, raising the cost to €4 billion/$5.6 billion or €2,434/kW or $3,400/kW in real money terms. These costs were confirmed in mid-2009, when EdF had already spent nearly €2 billion. In July 2011, EdF announced that the plant was expected to cost €6 billion, and pushed back the unit operating date to 2016.[50]
- NRG, in June 2009, said that the cost of two 1,350 MW GE Westinghouse units at the South Texas Project near Houston would be about $10 billion—not including financing costs. This would be a merchant plant, not a regulated one, operating on cost-plus basis with the first unit expected on line in 2016. At the time, this equated to $3,700/kW. However, in late 2009 Toshiba, the plant's main contractor, notified plant owners that costs would be up to $4 billion more.[51] In April 2011, NRG Energy Inc., the primary investor in the project, announced that it was abandoning the permitting process for the two new units due to the ongoing expense of planning the reactors combined with lower wholesale electricity prices and the uncertainty raised by the ongoing nuclear disaster in Fukushima; NRG subsequently wrote off its $331 million investment in the project.[52]
- The Finnish EPR at Olkiluoto has been plagued by many delays during construction and is currently three years behind schedule, having originally targeted commissioning in 2009. Citigroup noted that the original cost estimate for Olkiluoto was €3 billion. However, due to delays, planning problems (construction started in 2005), and issues with materials, a 2009 Areva estimate indicated that costs for the project increased by €2.3 billion and could increase further depending on the outcome of negotiations between the owner, TVO, and Areva on the timeline for completion. In June 2010, Areva announced €400 million of further provisions, taking the cost overrun to €2.7 billion, while the timescale slipped to the end of 2012 from June 2012, with operation set to start in 2013.[53] [54]

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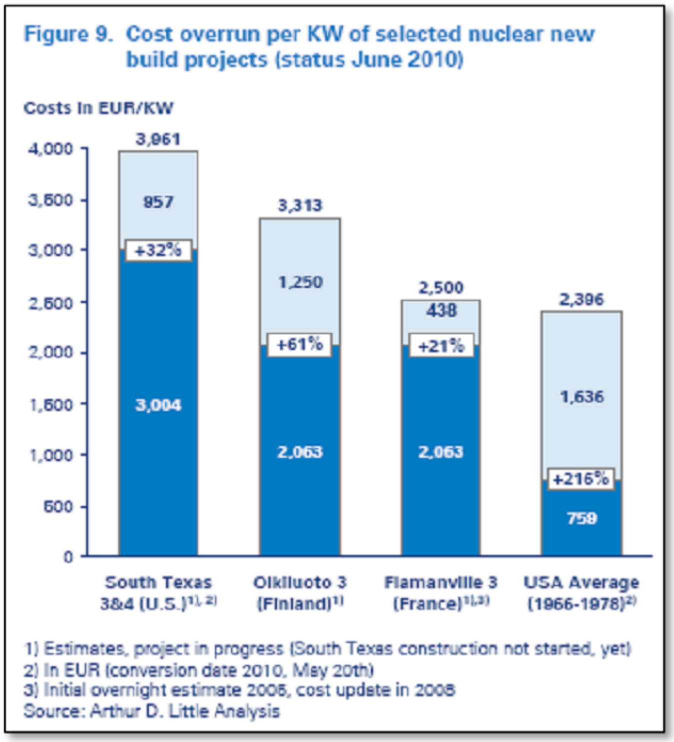
[47] http://chronicle.augusta.com/latest-news/2012-04-26/nrc-says-vogtle-rebar-differs-approved-design. Accessed May 1, 2012.
[48] http://www.platts.com/RSSFeedDetailedNews/RSSFeed/ElectricPower/6156322. Accessed May 1, 2012.
[49] Atherton, Peter., Simms, Andrew., Savvantidou, Sofia., and Hunt, Stephen. "New Nuclear- The Economics Say No" Citi Investment Research and Analysis. November 9, 2009. Available at https://www.citigroupgeo.com/pdf/SEU27102.pdf.
[50] "Flamanville-3 operations delayed to 2016." Platts. July 21, 2011.
[51] http://www.mysanantonio.com/news/environment/article/Nuclear-cost-estimate-rises-by-as-much-as-4-844529.php
[52] http://www.dallasnews.com/business/energy/20110419-nrg-ends-project-to-build-new-nuclear-reactors.ece
[53] http://www.mineweb.co.za/mineweb/view/mineweb/en/page72103?oid=107035&sn=Detail&pid=102055
[54] http://www.world-nuclear-news.org/NN-Startup_of_Finnish_EPR_pushed_back_to_2013-0806104.html

A 2010 research report issued by Arthur D. Little (ADL) shows the proportional increase associated with some of the examples noted above. Figure 9 from the ADL report (reproduced as Exhibit A-2 below) illustrates cost overruns from these examples.[55]

Exhibit A-2. ADL 2010 Cost Overrun Analysis



What is most telling about this exhibit, taken from the 2010 ADL report, is that current events have overtaken the estimates presented. As noted above, NRG has abandoned the permitting process for the proposed South Texas project and has written off $331 million in the process. Delays at Flamanville 3 have pushed the cost up to 6 billion euros, or about 3,000 euros/kW, and pushed delivery of the reactor to 2016. Flamanville 3 was originally estimated to cost 3.3 billion euros and to be completed in 2012.[56] Delays at Olkiluoto 3 have pushed back the operational date to 2014 from its original date of 2009.[57] As such, the exhibit demonstrates that both project risk and cost risk occur rapidly.

Factors Contributing to Cost Overruns

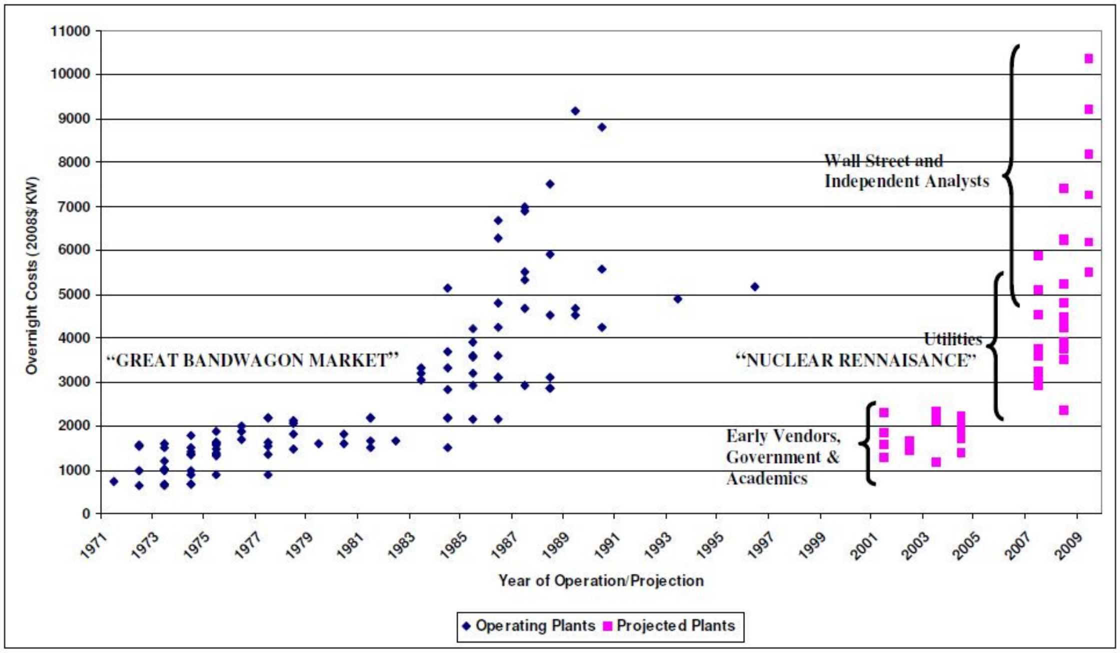
This section discusses factors and risks that are contributing to the cost overruns described above, and to nuclear cost overruns in general.

[55] Von Bechtolsheim, Matthias., Kruse, Michael., and Junker, Jan. "Nuclear New Build Unveiled: Managing the Complexity Challenge" Arthur D. Little. June 2010. Available at http://www.adl.com/reports.html?view=483.
[56] http://www.world-nuclear-news.org/NN_New_approach_puts_back_Flamanville_3_2107111.html. Accessed April 13, 2012.
[57] http://www.tvo.fi/www/page/2305/

Low utility cost estimates, compared to historical costs and analyst estimates

The largest component of nuclear power costs are the capital costs associated with the construction of the project.[58] The exhibit below compares the historical overnight capital costs (not including financing) in 2008$ of actual nuclear power plant projects, and plots some current estimated costs associated with announced projects from a 2009 report by Mark Cooper.[59]

Exhibit A-3. Nuclear Reactor Overnight Cost Estimates Taken from *Economics of Nuclear Reactors: Renaissance or Relapse*



Two trends are apparent in his analysis. One, history shows a dramatic incline in nuclear construction costs starting in the mid-eighties. Second, analyses of proposed projects by Wall Street and other independent third parties are less optimistic than either utility or academic cost projections for projects.

Limited experience with new reactor designs

A 2008 Synapse Energy Economics report detailed two major categories of risk that are impacting nuclear construction costs.60 These include:

- Limited experience in new reactor designs
- Competition for limited construction and fabrication materials and expertise

[58] Hogue, Michael. *A Review of the Costs of Nuclear Power Generation.* Bureau of Economic and Business Research, David Eccles School of Business, University of Utah. February 2012.
[59] Cooper, M. *The Economics of Nuclear Reactors: Renaissance or Relapse?* June 2009. Available at http://www.vermontlaw.edu/Documents/Cooper%20Report%20on%20Nuclear%20Economics%20FINAL[1].pdf.
[60] Gruebler. (2010).

Those risks have not diminished since our report, and continue to plague the nuclear industry. The actual experience of the AP1000 design is limited to the four units under construction in the United States, and the units under construction in China.

Despite new reactor designs, some old problems remain

As noted in a 2007 *Energy Policy* study, the estimated costs of the AP1000 reactor and other similar Generation III+ reactors are below the historical experience of constructed reactors in the United States. [61] In their conclusion of nuclear construction costs, the authors of the study state that:

> Those estimates may yet be proved right, but our data suggest the need for additional scrutiny of assumptions. While reactor designs have been standardized, licensing procedures have been streamlined, and construction management techniques are much more sophisticated than before, some old problems remain, and new ones may emerge. The policy and design changes represented by Gen III+ and Gen IV reactors do represent improvements over the current fleet, but the interlinked issues of reactor scale, customization of site-built technologies, slow electricity demand growth, intense competition from other energy sources, deregulated electricity markets, slow speed of industry learning, nuclear waste disposal, terrorism, and proliferation remain potential impediments to the cost competitiveness of next-generation nuclear power in the 21st century.

Large-scale infrastructure construction projects tend to cost more than estimated

A 2010 *Energy Policy* article on an analysis of the French nuclear industry notes that:

> These findings also suggest a need for in-depth sensitivity analysis across a much wider range of technological cost uncertainties. Perhaps climate policy analysis could begin by embracing in sensitivity analyses the engineering rule of thumb that large-scale infrastructure construction projects tend to always cost 2–3 times the original estimate. Nuclear is not the only example of a large-scale, complex technology that might be subject to this engineering rule: coal-based integrated gasification combined cycles with carbon capture and sequestration (or very large-scale solar plants in desert areas) would be prime candidates as well.

Additional factors contributing to overrunsIn testimony filed before the Florida Public Service Commission, Dr. Mark Cooper, testifying on behalf of SACE, identified additional factors that have influenced the cost of new nuclear reactors.[62] These include:

- Declining natural gas costs

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[61] Koomey, J., Hultman, N. *A reactor-level analysis of busbar costs for US nuclear plants,1970–2005*. Energy Policy 35(2007) 5630-5642.

[62] Cooper. (2010) p. 5.

- Declining estimates of carbon prices
- Declining demand due to the economic slowdown
- Reduced need for nonrenewable generation due to likely efficiency and renewable mandates in climate change legislation, which was pending at the time
- Rising projections of nuclear construction costs
- High degree of uncertainty in the economic environment that new reactors face

A more detailed description of these impacts is provided in his testimony. While Dr. Cooper's testimony is specific to Progress Energy (and the Levy 1 and 2 project), these risks are also applicable to Georgia Power, SCE&G, Duke, and to other proposed nuclear power plant construction projects.

Appendix C: Detailed Levelized Cost Inputs

In our analysis of Lee, we calculate the levelized costs of energy from the project. Levelization is a helpful way to compare the cost of different supply- and demand-side alternatives since it takes into account both investment and operating costs over time. It is the standard method for taking fixed and variable costs and converting them into a single total cost of energy, typically expressed as dollars per megawatt hour (MWh).

It is reasonable to think of levelized costs as a range rather than single point values since uncertainties exist in both investment and operating costs for different resources and technologies; differences in site-specific factors also influence costs for individual projects.

To identify a cost range for the Lee project, we first determined the low end of the range by converting the project costs currently reported by Duke to levelized costs.

The high-end cost estimate for the project was determined based on historical precedent (i.e., the project's increase in estimated cost between 2006 and 2010). Historical information provides a reasonable, if uncertain, proxy for future nuclear construction costs associated with a new, unproven design.[63]

The intention of the levelized cost analysis is to provide ratepayers and policymakers with a useful and plausible range of costs to reference in considering this project. However, our costs for this project do not include nuclear waste disposal and decommissioning costs, which constitute another, albeit uncertain, cost component of nuclear power.

The range in our cost estimate reflects the uncertainty associated with developing complex projects with the newly designed AP1000 reactor in this country

Following is a detailed description of the inputs used in the levelized cost assumptions for this analysis.

Lee Project Inputs

Major inputs for the Lee project included:

- 30 year levelization period
- 15-year accelerated depreciation
- 85 percent capacity factor
- Fixed and variable operations and maintenance costs of $93.9/kW-year based on AEO projections
- Debt equity ratio based on most recent rate case.
- The company's Return on Equity of 10.5 percent is based on the company's last base rate case, as determined by the North Carolina Utilities Commission.

[63] Kessides, I. Nuclear power: Understanding the economic risks and uncertainties. Energy Policy. 38(2010) 3849-3864. As noted by the author, "There is widespread agreement that the best predictors for the future costs of nuclear plants are based on actual experience rather than detailed engineering cost models and estimates."

- The Lee project cost estimates exclude the production tax credit since Lee 1 is not expected until 2021, after the cutoff date for the program. In addition, the Lee project does not include nuclear federal loan guarantees.

Exhibit B-1 below provides a summary of cost inputs for Lee based upon our described methodology.

Exhibit B-1. Detailed Levelized Cost Inputs and Results for Lee

Inputs	Unit	Low	Mid	High
Capital Cost	2010$/kW	$7,327	$10,990	$14,654
Levelized Real Fixed Charge Rate	%	8.78%	8.78%	8.78%
Capital Cost Annualized	$/kW-yr	$643	$965	$1,286
Fixed O&M	$/kW-yr	$93.9	$93.9	$93.9
Capacity Factor	%	85%	85%	85%
Capital Costs	$/MWh	$86.4	$129.5	$172.7
Fuel	Type	Uranium	Uranium	Uranium
Fuel Price	$/mmBtu	0.76	0.76	0.76
Heat Rate	Btu/kWh	10,488	10,488	10,488
Fuel Cost	$/MWh	7.97	7.97	7.97
Fixed and Variable O&M	$/MWh	13	13	13
Emission Cost	$/MWh	0.00	0.00	0.00
Production Tax Credit	$/MWh	0.00	0.00	0.00
All in Costs	**2010$ /MWh**	$107	$151	$194

Subsidies: Production Tax Credit and Loan Guarantees

Another important factor influencing the levelized cost of electricity for certain proposed nuclear energy projects is the availability of subsidies—namely the Production Tax Credits (PTC) and Federal Loan Guarantees. Neither of these subsidies apply to the Lee project; however, if the VC Summer project comes online as scheduled, it will receive the PTC (but not a Federal Loan Guarantee).

The PTC was included as part of the Energy Policy Act of 2005, and currently requires a unit to have an in-service date before January 1, 2021. The PTC totals 1.8 cents per kWh for the first 6,000 MW of capacity (nationwide) for the first eight years of operation. It is capped at $125 million per year per 1,000 MW of capacity.

VC Summer 2 and 3 are currently scheduled to come online in 2017 and 2019. If completed as scheduled, both units will receive the full amount of the PTC. On the other hand, in our analysis of the Lee project, we have assumed that Lee 1, slated for delivery in 2021, will not meet the PTC cut-off date. Lee 2, which is projected to come online in 2023, does not receive the PTC either.

While the PTC reduces the cost of the VC Summer project for developers and, ultimately, ratepayers, it is not free money. The project costs covered by the PTC are paid by taxpayers.

So far, the only proposed nuclear project to receive a Federal Loan Guarantee is Georgia Power's Vogtle project (Units 3 and 4). In February 2010, the DOE announced that it had awarded, on a conditional basis, $8.33 billion in federal loan guarantees to underwrite the construction costs of this project. Under the terms of the agreement, the loan guarantees would allow Georgia Power and the other owners of the project to borrow at below-market Federal Financing Bank rates with the assurance of the U.S. Government.[64] Duke applied for the loan guarantee program, but it was not awarded by the DOE.

The federally backed loan guarantee reduces the project's financing costs and allows the Vogtle 3 and 4 owners to increase their debt financing and reduce their equity requirements. Since the cost of equity is much greater than the cost of borrowing, this substantially reduces the levelized cost for the plant.

While these loan guarantees will covey considerable benefits to the plant's developers, they pose risks to U.S. taxpayers. How significant are these risks? The federal loan guarantee program, authorized by Congress in 2005, came about because investors would not provide financing for the new-generation nuclear energy projects without them. When institutional lenders denied financing to these projects, Congress put taxpayer dollars on the line to shoulder the risks that neither Wall Street nor the utilities themselves were willing to bear.

In recent months, public attention has focused on the bankruptcy of Solyndra, a recipient of $535 million from a similar DOE loan guarantee program. Fallout from the attention on Solyndra and other recipients makes this program less certain in the future and has impacted the closing of the loan guarantee for Vogtle 3 and 4.[65] Executives from Southern Company indicated the difficulties in finalizing the DOE loan guarantee and suggested that Georgia Power would proceed even if the loan guarantees fall to finalize.[66]

Rate and Bill Impact Analysis

We have detailed our assumptions used to estimate the proposed rate and bill impacts from the Lee project below:

- Rate base used in calculations based on information taken from Duke's most recent rate case in the NCUC Docket E-7 Sub 989.[67]
- Energy and number of residential customers based on filings from Duke's most recent rate case.
- The Company's return on equity based on Duke's most recent rate case.
- Allocation of residential revenue requirements based on Duke's most recent rate case.

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[64] http://www.ucsusa.org/nuclear_power/nuclear_power_and_global_warming/nuclear-loan-guarantees.html. Nuclear power plant project owners will have to pay a Credit Subsidy Fee that in theory covers the risk of default; however, the nuclear industry is lobbying to have the fee set at around 1 percent of the principle of the loan guarantee.

[65] McArdle, J. *Solyndra: As controversy simmers, Obama seeks no new funding for DOE loan guarantees.* EnergyWire. (February 14, 2012). Available at http://www.eenews.net/public/EEDaily/2012/02/14/1. Accessed April 10, 2012.

[66] http://online.wsj.com/article/BT-CO-20120425-719348.html. Accessed May 1, 2012.

[67] Responses to E-1 Item 41 in NCUC Docket E-7 Sub 989 dated July 1, 2011. Available at http://ncuc.commerce.state.nc.us/docksrch.html. Accessed April 27, 2012

- Base electricity rates and service charge from Duke Energy Carolinas' residential rate schedule.[68]
- We have not made any adjustments for the possible effects of load growth on rates.
- We have not made any general inflation adjustment to the current rates which over the next ten years might be in the order of 1-2% per year.

[68] Available at http://www.duke-energy.com/pdfs/NCScheduleRS.pdf. Accessed April 27, 2012