North Carolina Utilities Commission
Public Staff

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Disclaimer

This ratemaking presentation provides a high level overview of the general ratemaking process for regulated utilities in North Carolina. Ratemaking is a fact-specific process, thus examples discussed herein may not always predict the outcome of any particular issue coming before the NCUC. The purpose of this presentation is to provide the audience with a better understanding of the framework within which decisions are made and the issues that regulators must weigh when reaching those decisions and should not be construed as offering opinions regarding the Public Staff’s position in any present or future case. Many of the graphs contained herein are fictional examples for illustrative purpose only and should not be cited or relied upon.
Who Is The Public Staff?

- Represents the using and consuming public in North Carolina Utilities Commission proceedings
  - Not the public at-large
  - Economic regulator and advocate
- Eighty staff members organized into nine divisions
  - Electric, natural gas, communications, water/sewer, transportation
  - Accounting
  - Legal
  - Economic research
  - Executive
  - Consumer complaint analysts
Key Functions

• Appear in NCUC proceedings on behalf of utility customers
• Investigate customer complaints
• Audit public utilities in NCUC rate proceedings
• Undertake studies and make recommendations to NCUC
  • Proposed new service offerings and changes to existing services
  • Proposed construction of generating facilities and transmission lines
  • Mergers and acquisitions involving public utilities
• Interface with general public on utilities issues
• Present testimony and recommendations to NCUC
• Assist legislative staff and legislators regarding proposed legislation as requested
• Work with other State agencies (e.g., DEQ, Dept. of Commerce) as well as counties and municipalities on regulated utility matters
• Provide information and guidance to parties who intervene in cases before the NCUC
Differences Between NCUC and Public Staff

- Independent agencies
  - Separate staffs, leadership and budgets
- NCUC does not direct or oversee the Public Staff’s operations
- Public Staff appears as a party before the NCUC
  - Public Staff subject to ex parte rules and cannot independently communicate with NCUC on pending matters
  - Public Staff does not participate in NCUC decision-making
- Staff roles
  - NCUC staff is an advisory staff
  - Public Staff is an audit/advocacy staff
Regulated Utilities

• NCUC regulates the rates and service of “public utilities” as defined in Chapter 62 of North Carolina General Statutes
  • Producing or delivering a utility service to the public for compensation
    • If you give utility service away for free, you are not a regulated public utility

• Public utilities are usually private, investor-owned entities
  • Considered to be a “public” utility because they are entities affected with the public interest
Non-Regulated Utility Rates

- Municipal utilities
  - Rates are set by municipality or related board
- Electric membership cooperatives
  - Rates are set by member-elected board of directors
- Water/sewer authorities and sanitation districts
  - Rates set by governing board selected by participating municipalities
Fundamental Ratemaking Questions

• It is important to understand the framework through which spending decisions are evaluated
  • Utility operating expenses are evaluated using general ratemaking principles
  • If these expenses do not conform to cost of service principles, regulators are less likely to allow recovery through rates
• Fundamental question for utilities:
  “Can we recover it through rates?”
• Fundamental questions for regulators:
  “Does it benefit ratepayers?”
  “Is it least cost?”
What Is The Regulatory Compact?

- In exchange for a regulator granting the utility a protected monopoly within its service territory, the utility commits to supply the full quantities demanded by customers at a regulated price
  - Public utility is not subject to competition within its service territory
  - Public utility has an obligation to serve anyone that requests service
  - Rates are regulated based upon the cost of service, which includes a reasonable rate of return
Energy v. Capacity

- **Energy** is actual electricity being produced or consumed
  - Measured in kilowatt hours (kWh) or megawatt hours (kWh)
- **Capacity** is the infrastructure needed to produce electricity
  - Measured in kilowatts (kW) or megawatts (kW)
- Average monthly residential consumer bill: $110/month
  - Energy v. capacity
    - 54% composed of energy costs
    - 46% composed of capacity costs
  - Generation v. transmission/distribution
    - 64% composed of generation costs
    - 36% composed of transmission/distribution costs
Capacity Requirements and Utilization

Load Duration Curve

- Peaking Load Capacity
- Total Capacity Requirement
- Load Following Capacity
- Base Load Capacity

Capacity Requirement (kW)
Capacity Utilisation (% of Time)
Peak Demand

- Utility must have enough capacity to meet peak demand
- Capacity must be **firm** and **dispatchable**
  - When you need power, it has to produce instantly
  - Cannot be intermittent
- When customer demand equals or exceeds generation output, the utility must:
  - Bring additional generation online
  - Purchase power from another source
  - Implement demand response measures
  - Curtail customer usage
Peak Demand

• Peak demand continues to increase each year
  • No longer correlates to overall energy consumption
• Peak demand driven by variety of devices
  • Air conditioning and heating
  • Washing machines/dryers/dishwashers
  • Ovens/stoves
  • Electronics such as large screen televisions, computers, etc
• System must be sized to meet peak demand
  • North Carolina’s all-time system peak occurred on February 20, 2015 between 7:00 am and 8:00 am
    • DEC: 21,348 MW
    • DEP: 15,196 MW
Energy v. Capacity

US Generated Energy vs. Peak Demand

Data Source: EIA
Demand Profiles
Seasonal Demand Variations

![Graph showing seasonal demand variations with peak hours marked as Winter Peak and Summer Peak.](image-url)
Rate Case Process – 270 Days

1) Utility files rate case application, exhibits, testimony and proposed rates
2) NCUC suspends rates and schedules customer and evidentiary hearings
3) Public Staff engages in discovery, audits/investigates, files testimony
4) Intervenors engage in discovery and file testimony
5) Settlement discussions may occur between parties
6) Customer and evidentiary hearings
7) Parties file proposed orders
8) NCUC reviews all evidence and issues order
9) Utility puts new rates into effect
General Ratemaking

• Utility base rates established pursuant to N.C. Gen. Stat. § 62-133
  • Must be just and reasonable
• Based on the cost of service in the test period, adjusted for non-recurring or non-representative costs
• Rates are established to recover future costs based on what the utility has already spent
  • Utilities typically do not recover expenses and capital costs in advance or after the fact
Least Cost Requirement

• N.C. Gen. Stat. § 62-2(3a) requires “...energy planning and fixing of rates in a manner to result in the least cost mix of generation and demand side reduction measures which is achievable...”
• Look for the reasonable least cost means of energy production and regulatory compliance
• This does not mean utilities buy the cheapest thing
  • Balance short-term and long-term costs
    • Consider reliability, maintenance, replacement, estimated obsolescence
  • Present value calculations
Test Year

- Financial data from a historical 12-month period
  - Serves as a proxy for the anticipated level of costs for the period of time the rates will be in effect
  - Pro forma update to include period prior to the hearing
- Example:
  - Rate case filed on March 31, 2016
  - Hearing date of August 1, 2016
  - Test year of January 1, 2015 – December 31, 2015
General Ratemaking Formula

- **Revenue Requirement** is determined as \((\text{Rate Base} \times \text{Rate of Return} \text{ (grossed up for income taxes)}) + \text{Expenses}\)

- **Rate Base** – value of the property (net of depreciation) on which a utility may earn a rate of return.
  - Must be “used and useful” - Power plants, transmission and distribution lines, etc. actually used in providing service to customers

- **Rate of Return** – % return that utility may earn on invested capital, including debt and equity investments.

- **Expenses** – can recover reasonable and prudent expenses based on an historical test year.
Rate Base

- Rate base is the *reasonable and prudent* cost of property on which a public utility is authorized to earn its rate of return.

- Rate base calculation:
  - **Original cost of the utility assets** *(prudent capital investment)*
  - *(minus)*
  - **Accumulated depreciation expense**
Original Cost

- Original cost of the assets also includes capital additions since original construction
  - Example: The addition of an emissions control system on a generating plant would be folded into the original cost of the assets when calculating rate base

- The assets included in rate base must be used and useful
  - Utility cannot recover investment if it builds assets that it does not need
  - Reasonable planning horizon is allowed
Accumulated Depreciation

- Capital investment is recovered through the depreciation expense established in the test year
- Accumulated depreciation expense deducted from original cost to avoid double recovery
Utility Assets in Rate Base

- Generation facilities
- Transmission lines
- Distribution lines
- Transformers and substations
- Meters
- Computer and software systems
- Vehicles
- Equipment
- Buildings
- Pipelines
- Working capital
# Adjustments to Rate Base

DUKE ENERGY CAROLINAS, LLC  
Docket No. E-7, Sub 1026  
North Carolina Retail Operations  
ORIGINAL COST RATE BASE  
For the Test Year Ended June 30, 2012  
(In Thousands)

<table>
<thead>
<tr>
<th>Line No.</th>
<th>Item</th>
<th>N.C. Retail Adjusted Per Company 1/</th>
<th>Public Staff Adjustments 2/</th>
<th>After Public Staff Adjustments 3/</th>
</tr>
</thead>
<tbody>
<tr>
<td></td>
<td></td>
<td>(a)</td>
<td>(b)</td>
<td>(c)</td>
</tr>
<tr>
<td>1</td>
<td>Electric plant in service</td>
<td>$23,072,491</td>
<td>$5,342</td>
<td>$23,077,833</td>
</tr>
<tr>
<td>2</td>
<td>Accumulated depreciation and amortization</td>
<td>(9,102,912)</td>
<td>(311,043)</td>
<td>(9,413,955)</td>
</tr>
<tr>
<td>3</td>
<td>Net electric plant in service (L1 + L2)</td>
<td>13,969,579</td>
<td>(305,701)</td>
<td>13,663,878</td>
</tr>
<tr>
<td>4</td>
<td>Materials and supplies</td>
<td>551,282</td>
<td>30,358</td>
<td>581,640</td>
</tr>
<tr>
<td>5</td>
<td>Working capital</td>
<td>664,503</td>
<td>23,724</td>
<td>688,227</td>
</tr>
<tr>
<td>6</td>
<td>Accumulated deferred income taxes</td>
<td>(3,091,373)</td>
<td>(125,866)</td>
<td>(3,217,239)</td>
</tr>
<tr>
<td>7</td>
<td>Operating reserves</td>
<td>(203,875)</td>
<td>-</td>
<td>(203,875)</td>
</tr>
<tr>
<td>8</td>
<td>Construction work in progress</td>
<td>-</td>
<td>-</td>
<td>-</td>
</tr>
<tr>
<td>9</td>
<td>Total original cost rate base (Sum of L3 thru L8)</td>
<td>$11,890,116</td>
<td>($377,485)</td>
<td>$11,512,631</td>
</tr>
</tbody>
</table>

Fernald Exhibit 1  
Schedule 2
Rate of Return

• Percentage return that the utility is allowed to earn on its invested capital
• Designed to compensate investors for the use of their capital and associated risk
• Rate of return composed of three components:
  • Cost of equity
  • Cost of debt
  • Capital structure (debt and equity ratios)
• Rate of return is not a guaranteed return → it is the return the utility is authorized to earn
  • Rates are calculated using the rate of return
Rate of Return – Cost of Debt

• Debt is considered less risky than equity
  • Debt has senior claim on utility earnings
    • If utility bankrupts, debt holders are paid out before equity owners
• Lower risk results in lower required rate of return for debt as compared to equity
• Cost of debt calculation is straightforward
  • Based on the coupon (interest) rate of the debt
• Interest on debt is tax deductible
• Influenced by utility’s credit rating and risk profile
  • Standard & Poor’s (AAA to D)
    • Duke Energy Carolinas: A
    • Duke Energy Progress: A
    • Dow Jones US Utilities average: BBB+
  • Fitch (AAA to D)
  • Moody’s (Aaa to C)
Rate of Return – Cost of Equity

- Equity is considered more risky than debt
  - Equity has junior claim on utility earnings due to the contractual nature of debt
    - Shareholders get what is left once everyone else has been paid
- Higher risk → Higher rate of return required to induce investors to bear the risk
- Cost of equity is not tax deductible
- Cost of equity cannot be precisely calculated
  - Methodologies for estimating cost of equity
    - Discounted Cash Flow (DCF)
    - Capital Asset Pricing Mechanism (CAPM)
    - Risk Premium model
Cost of Equity: Risk

• Typical utility risks include:
  • Disallowed cost recovery
  • Regulatory lag
  • Environmental regulations
  • Flotation costs
  • Disruptive technologies
  • Stranded costs
  • Commodity risks
Cost of Equity: Risk

- Utility cost of equity is generally lower than unregulated businesses
- Utilities are considered less risky than other businesses
  - Utilities can file a rate case to recover reasonable and prudent investment/expenses
    - Unregulated companies are at mercy of market forces
  - Electricity, water and sewer are daily necessities with sustained, predictable demand
    - Food, computers, vehicles, clothes and entertainment are more fungible
- Greater use of riders and other rate recovery mechanisms outside a rate case reduces utility risk, which reduces cost of equity
Rate of Return – Capital Structure

- Ratio of debt to equity impacts the ultimate cost to ratepayers and must be balanced appropriately
  - Since equity is more costly than debt, a higher percentage of equity will result in higher rates
  - BUT the cost of equity increases as a company adds more debt, which offsets the savings
- Typical capital structure ratio for ratemaking is 50:50
- Utilities Commission can impute capital structure for ratemaking purposes
  - Example: Utility A is capitalized with 65% equity and 35% debt. NCUC could establish rates by applying a 50% equity and 50% debt ratio to the rate base. This would result in lower rates for customers when compared to the actual capitalization ratio.
Rate of Return – Example Calculation

• Utility A has a capital structure of 55% equity and 45% debt
• Cost of equity estimated at 10%
• Income tax rate of 40%
• Cost of debt calculated at 4%
• Rate base is $3,000,000,000
• Overall rate of return = 7.30%

<table>
<thead>
<tr>
<th>Type of Capital</th>
<th>Capital Structure Ratio %</th>
<th>Cost Rate %</th>
<th>Weighted Cost %</th>
<th>Income Tax Gross-Up</th>
<th>Pre-Tax ROR %</th>
</tr>
</thead>
<tbody>
<tr>
<td>Equity</td>
<td>55.00%</td>
<td>10.00%</td>
<td>5.50%</td>
<td>1.67</td>
<td>9.17%</td>
</tr>
<tr>
<td>Debt</td>
<td>45.00%</td>
<td>4.00%</td>
<td>1.80%</td>
<td>1.00</td>
<td>1.80%</td>
</tr>
<tr>
<td>Total</td>
<td>100.00%</td>
<td></td>
<td>7.30%</td>
<td></td>
<td>10.97%</td>
</tr>
</tbody>
</table>

• Pre-tax return (includes income tax gross-up) on rate base = $3,000,000,000 * 10.97% = $329,100,000
Expenses

• Utilities are authorized to recover *reasonable and prudent* expenses
  • Maintenance expense
  • Operating expense
    • Depreciation
    • Salaries
    • Fuel
    • Transportation
    • Customer service
    • General taxes
    • Administrative
    • Uncollectibles
    • Testing
    • Legal
    • Rate case expenses
    • Purchased power costs
    • Unbundled QF power costs
Depreciation Expense

- Depreciation amount charged during the test year
- Designed to recover the cost of the property over its estimated life
  - Sample depreciation rates (2011 study)
    -Coal generating plant: 60 years
    - Transmission facilities: 60 years
    - AMI meters: 15 years
    - Natural gas combined cycle: 40 years
    - Distribution facilities: 40 years
    - Computers: 5 years

- If item is fully depreciated but remains in utility service, there is no depreciation expense in the test year
  - Just because it is fully depreciated does not mean it is retired
  - Utility has fully recovered its capital investment and the rate of return
  - No longer earn rate of return on such property going forward
Expenses

• Ongoing level of expenses going forward based on the expenses incurred during the test year
  • Pro forma update to include known changes in expense levels between filing and hearing
• Adjustments to test year expenses are common
  • Common disallowances include:
    • Portions of executive salaries and bonuses
    • Lobbying costs
    • Public relations
    • Charitable expenses
    • Expenses not representative of expected expense levels going forward
Cost Allocation

- Attribute costs to different customer classes based on the cost incurred to serve those classes
  - Residential, commercial and industrial classes
    - Capital requirements vary by customer class
      - Residential customers require significant distribution facilities
  - Economies of scale
    - Municipalities and industrial customers are cheaper to serve on a per kWh basis
  - Time differentiation
    - Contribution to peak vs. non-peak demand
  - Retail vs. wholesale
    - Municipalities and electric cooperatives
  - System costs across multiple state jurisdictions
    - North Carolina/South Carolina allocate costs approximately 65:35
Cost Components

• Demand
  • Production, transmission and distribution facilities
  • Tend to be fixed in nature

• Energy
  • Fuel expense, purchased power, generator maintenance
  • Vary with the number of kilowatt-hours generated

• Customer
  • Function of number of customers
  • Includes minimum system components necessary to provide electric service to customer-specific locations
Cost Allocation Methodologies

- Summer coincident peak
  - Customer’s share of the system load at the system’s summer peak
- Winter/summer coincident peak and average demand
- Non-coincident peak and average demand
- Twelve month average peaks

- North Carolina allocates based on load demand at summer coincident peak
Rate Design

• Rates established to meet the revenue requirement
  • Customer rate classes
    • Residential
    • Commercial
    • Industrial
  • Designed to mirror the cost of service to each class
    • Various rate schedules in each customer class
• Average 2015 retail price of electricity per customer class
  • Residential: 11.32 cents/kWh (National average: 12.67 cents/kWh)
  • Commercial: 8.71 cents/kWh (National average: 10.59 cents/kWh)
  • Industrial: 6.40 cents/kWh (National average: 6.89 cents/kWh)

Source: Energy Information Administration (Dec 2015)
Fixed and Variable Costs

- Rate design includes fixed and variable components
  - Fixed (minimum) charges on the bill tend to be low
    - Designed to ensure customer pays a certain portion toward the fixed cost of the system
    - Do not reflect the true fixed cost of the system to serve the customer
    - Much of the fixed cost is recovered through the variable component
  - Variable charges can be influenced by customer behavior
    - Largest variable cost is fuel
    - Some customers may pay less than the true fixed cost the utility incurs to serve them
      - Cost recovery shifted to higher users
Impact of Tariff Designs

• Standard service
  • Small fixed charge, with most costs recovered through variable kilowatt-hour charge
  • Based on how much you use
• Time-of-Use
  • Rates are higher when demand is higher
  • When you use energy is as important as how much you use
  • Requires a smart meter
• Curtailable Service
  • Lower rate in exchange for ability to be curtailed a certain number of hours each year
  • Premium charge if exceed demand during curtailment period
• Co-Generation
  • Customer self-generation
  • Demand and standby charges
How Should Costs Be Allocated?

- System Load at Peak
- Residential Load
- Commercial Load
- Industrial Load
How Should Costs Be Allocated?

**System Load at Peak**

**Customer X Load at Peak**

**Customer Y Load at Peak**
How Should Costs Be Allocated?

![Graph showing how costs should be allocated. The graph displays the system load at peak, residential load, commercial load, and industrial load over the course of a day. The utility generation capacity is also indicated.](image-url)
Other Ratemaking Concepts

• Construction Work in Progress (CWIP)
  • Generally not included in rates until construction is complete and the plant is in service

• Allowance for Funds Used During Construction
  • Utility is allowed to accrue financing costs (debt and equity return) on the funds used for construction
    • Included in rate base along with the capital costs once project is complete
    • In certain circumstances, the financing costs incurred-to-date can be recovered as CWIP in a general rate case before the project is complete

• Early Retirement/Abandoned Plant
  • Unrecovered costs can be recovered when the early retirement/abandoned plant decision is deemed reasonable and prudent
    • NCUC has allowed sharing of risk by disallowing rate of return on the amount recovered
Regulatory Assets (Deferrals)

- Deferred Expenses
  - Regulator may allow a utility to record costs that would normally be expensed as an asset (called a regulatory asset)
    - Applies to both revenues and expenses
    - Must demonstrate the costs in question would have a material impact on the utility’s earnings and overall financial condition absent the deferral
      - Utility must be earning below its authorized rate of return
      - Can include a rate of return on the deferred amount
  - Rates set by a regulator at a later date include recovery of the regulatory asset
  - NCUC has said these should be used sparingly
Rate Case or Not?

- Last rate case in 2008
- $15 billion rate base
- Return on Equity
  - Established ROE of 10.0%
  - Currently earning -2.2%
  - Similar utility received ROE of 10.25% last year
- Lost a significant industrial customer in 2015
Rate Case or Not?

• Last rate case in 2013
• $225 billion rate base
• Return on Equity
  • Established ROE of 10.5%
  • Currently earning 13.0%
  • Similar utility received ROE of 10.0% last year
• Brought $2 billion generating plant online in 2015
• Customer growth of 2.5%
Rate Case or Not?

- Last rate case in 2013
- $225 billion rate base
- Return on Equity
  - Established ROE of 10.5%
  - Currently earning 12.0%
  - Similar utility received ROE of 10.0% last year
- Brought $1 billion generating plant online in 2015
  - NCUC issued order granting a deferral with rate of return
- Customer growth of 2.5%
Rate Case or Not?

- Last rate case in 2004
- $50 billion rate base
- Return on Equity
  - Established ROE of 10.5%
  - Currently earning 9.5%
  - Similar utility received ROE of 10.5% last year
- No significant new utility plant added since last rate case
  - Several plants fully depreciated since last rate case
- Computer system replacement in fall 2015
- Demand declining at 1% annually
Fuel Rider

- Cost of fuel burned
  - Coal, gas, nuclear, biomass
- Cost of reagents used to treat emissions
- Certain purchased power costs
  - Replacement power costs
  - Peak power purchases
- Costs of energy purchases from qualifying facilities
  - Biomass, landfill gas
  - Solar purchases if bundled with REC
Renewable Energy/Energy Efficiency Portfolio Standard Rider

• Incremental costs to comply with Renewable Energy Portfolio Standard (bundled costs minus avoided costs)
• Costs of Renewable Energy Certificates (RECs)
• Costs recoverable are capped by General Assembly
  • Beginning on January 1, 2015
    • Residential rates: $34/year
    • Commercial rates: $150/year
    • Industrial rates: $1,000/year
Demand Side Management (DSM)/Energy Efficiency (EE) Rider

• Costs of DSM/EE programs
  • CFL bulbs
  • Refrigerator recycling program
  • Home energy audits
  • Load control
• Net lost revenues
  • First three years of program
• Utility incentives
  • Earn rate of return on energy efficiency expenditures similar to invested capital
DSM/EE programs – Cost Effectiveness Tests

- Participant Cost Test (PCT)
  - Will the participant-customer benefit from installing the measure?
- Utility Cost Test (UCT)
  - Will the administrative cost to the utility increase?
- Ratepayer Impact Measure Test (RIM)
  - Will utility rates increase?
- Total Resource Cost Test (TRC)
  - Will the total costs of energy in the service territory decrease?

- North Carolina uses the TRC as the primary test
  - Utility required to provide analysis of PCT, UCT, RIM and TRC
  - UTC used to determine the incentive payment to utility
Applying Cost Effectiveness Tests

- DNCP requested DSM/EE program approval (2013)
  - Residential Heat Pump Upgrade
  - Residential Home Energy Check Up
    - Did not pass Utility Cost Test (UTC)
    - Did not pass Total Resource Cost Test (TRC)
  - Residential Duct Testing and Sealing
    - Did not pass Total Resource Cost Test (TRC)
  - Non-Residential Energy Audit
  - Commercial HVAC Upgrade

- NCUC approved programs as a portfolio because the cumulatively met the cost-effectiveness tests
NCEMPA Asset Acquisition Rider

• Recovers the costs associated with Duke Energy Progress’ purchase of generation assets from the North Carolina Eastern Municipal Power Agency in 2015
• Adjusted annually to reflect savings/expense associated with changes in the fuel cost
Public Utility Regulatory Policies Act of 1978

- Defines Qualifying Facilities (QFs)
  - Small power production facilities 80MW or less and whose primary energy source is renewable resources
  - Co-generation facilities sequentially producing electricity and another useful form of thermal energy
- Electric utilities “must purchase” electricity and capacity generated by QFs
  - Can be excused if access to sufficiently competitive market exists
    - IE: PJM, MISO, etc.
  - Electricity is purchased from QFs at the utility’s avoided cost
    - Established by state utility commission for regulated utilities
- Electric utilities “must sell” electricity and capacity when requested by a QFs
Avoided Cost Rates

• Incremental cost a utility would incur to generate or purchase the next kilowatt or kilowatt-hour of electricity
  • Cost of building the capacity
  • Cost of generating the energy
• “Avoided” because the utility has procured the electricity from another source rather than incurring the cost to produce the electricity itself
• Established for regulated electric utilities by the NCUC not less than every two years
How is Avoided Cost Calculated?

• North Carolina uses the Peaker Method
  • Capacity calculation based on the cost (per kW) of building a new peaking unit
    • Natural gas combustion turbine (peaking unit)
  • Energy calculation based on marginal system energy cost
  • Avoided cost elements must be “known and quantifiable”
• Variable and long-term fixed rate options
• Capacity payments are paid only for peak hours during which the unit is producing electricity
## Sample Avoided Cost Tariff

**Option A**

**Administrative Charge**

$19.91 per month

**Interconnection Facilities Charge**

The Interconnection Charge for each customer is set forth in the Agreement as outlined in the Terms and Conditions; however, the $25.00 minimum will not apply if the charge is for a meter only.

<table>
<thead>
<tr>
<th>Interconnected to Distribution System:</th>
<th>Variable Rate</th>
<th>5 Years</th>
<th>10 Years (a)</th>
<th>15 Years (a)</th>
</tr>
</thead>
<tbody>
<tr>
<td>I. Capacity Credit</td>
<td></td>
<td></td>
<td></td>
<td></td>
</tr>
<tr>
<td>a. All On-Peak Energy per On-Peak Month per kWh:</td>
<td></td>
<td></td>
<td></td>
<td></td>
</tr>
<tr>
<td>i. Hydroelectric facilities with no storage capability and no other type generation</td>
<td>3.34¢</td>
<td>3.45¢</td>
<td>3.64¢</td>
<td>3.82¢</td>
</tr>
<tr>
<td>ii. for all other hydroelectric and all non-hydroelectric facilities</td>
<td>2.00¢</td>
<td>2.07¢</td>
<td>2.19¢</td>
<td>2.29¢</td>
</tr>
<tr>
<td>b. All On-Peak Energy per Off-Peak Month per kWh:</td>
<td></td>
<td></td>
<td></td>
<td></td>
</tr>
<tr>
<td>i. Hydroelectric facilities with no storage capability and no other type generation</td>
<td>1.67¢</td>
<td>1.73¢</td>
<td>1.82¢</td>
<td>1.91¢</td>
</tr>
<tr>
<td>ii. for all other hydroelectric and all non-hydroelectric facilities</td>
<td>1.00¢</td>
<td>1.04¢</td>
<td>1.09¢</td>
<td>1.15¢</td>
</tr>
<tr>
<td>II. Energy Credit</td>
<td></td>
<td></td>
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<tr>
<td>a. All On-Peak Energy per Month per kWh:</td>
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<tr>
<td>b. All Off-Peak Energy per Month per kWh:</td>
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</tbody>
</table>

<table>
<thead>
<tr>
<th>Interconnected to Transmission System:</th>
<th>Variable Rate</th>
<th>5 Years</th>
<th>10 Years (a)</th>
<th>15 Years (a)</th>
</tr>
</thead>
<tbody>
<tr>
<td>I. Capacity Credit</td>
<td></td>
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<tr>
<td>a. All On-Peak Energy per On-Peak Month per kWh:</td>
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</tr>
<tr>
<td>i. Hydroelectric facilities with no storage capability and no other type generation</td>
<td>3.26¢</td>
<td>3.37¢</td>
<td>3.56¢</td>
<td>3.73¢</td>
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<tr>
<td>ii. for all other hydroelectric and all non-hydroelectric facilities</td>
<td>1.96¢</td>
<td>2.02¢</td>
<td>2.14¢</td>
<td>2.24¢</td>
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<tr>
<td>b. All On-Peak Energy per Off-Peak Month per kWh:</td>
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<td></td>
<td></td>
</tr>
<tr>
<td>i. Hydroelectric facilities with no storage capability and no other type generation</td>
<td>1.63¢</td>
<td>1.69¢</td>
<td>1.78¢</td>
<td>1.87¢</td>
</tr>
<tr>
<td>ii. for all other hydroelectric and all non-hydroelectric facilities</td>
<td>0.98¢</td>
<td>1.01¢</td>
<td>1.07¢</td>
<td>1.12¢</td>
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<td>II. Energy Credit</td>
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<tr>
<td>a. All On-Peak Energy per Month per kWh:</td>
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<td>b. All Off-Peak Energy per Month per kWh:</td>
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</tbody>
</table>
Sample Avoided Cost Calculation

- 3MW solar facility under 10 Year Contract
- Connected to Transmission System
- Utilizing Option A
  - Peak hours: Monday – Friday
    - 7:00 AM to 11:00 PM
  - Peak months: June – September; December – March
  - 28% Capacity Factor over 24 hour period/366 days

**Avoided Energy Cost payment**
Off-peak [$0]= 3,000kW * 4,176 hrs * .00 * .0371
On-peak [$276,369]= 3,000kW * 4,608 hrs * .42 * .0476

**Avoided Capacity Cost payment**
On-Peak Energy per On-Peak Month [$82,833]= 3,000kW * 3,072 hrs * .42 * .0214
On-Peak Energy per Off-Peak Month[$18,551]= 3,000kW * 1,376 hrs * .42 * .0107

**Total annual avoided cost payment = $377,753**
How is Avoided Cost Used?

- Rates for purchases from Qualifying Facilities
- Integrated Resource Plans
  - Allows utilities to assign dollar value to their options
- Determining savings from Demand Side Management/Energy Efficiency Programs
  - What did the utility save by avoiding the demand?
- Determining incremental costs of Renewable Energy Portfolio Standards compliance
  - What additional cost did the utility incur above the cost of the energy/capacity?
Ratemaking Examples

• Duke Energy builds a gas plant
  • Capital costs are included in base rates during general rate case
    • If plant incomplete at time of rate case, possible recovery of capital costs, including financing costs, to date
  • Changes in fuel costs are recovered/refunded through the Fuel Rider

• Duke Energy builds a biomass facility for REPS compliance
  • Capital costs are included in base rates during general rate case
  • Changes in fuel costs are recovered/refunded through the Fuel Rider
  • Incremental costs (costs above avoided costs) are recovered through the REPS Rider

• Duke Energy purchases solar power from QFs under PURPA
  • Avoided energy costs paid to QFs are recovered through Fuel Rider if bundled with RECs
    • Avoided energy costs recovered through base rates if not bundled with RECs
  • Capacity costs paid to QFs recovered through base rates
  • Facilities constructed to interconnect and move QF power are paid by QF
Consumer Advocate Perspective

• Rates should be based on the **cost of service**
  • How much does it cost to provide safe, reliable service?
  • Should be based on **least cost** means for providing service

• Expenditure decisions should be both **reasonable and prudent**
  • Was the decision to build the plant prudent?
  • Were the costs incurred following the decision reasonable?

• Rates **allocate risk** between customers and utility shareholders
  • What is the appropriate allocation of risk?
Traditional Consumer Expectations

- Customers expect utility service that is:
  - Reliable
  - Safe
  - Reasonably priced
- Value for their money
- Stability and predictability in monthly utility bills
- Timely and responsive customer service
- Quick restoration following outage
Customer Expectations Are Changing

• Greater information regarding their energy usage and bill
  • Mobile applications, real-time data
  • Social media
• Greater control over their energy costs
  • Ability to impact their bill amount through behavioral changes
• Fewer outages and quicker restoration times
  • Information regarding restoration efforts
• Reasonable vegetation management
• Specific customer groups have unique concerns
  • Movement away from fossil-fueled energy generation
  • Ability to purchase from third parties
  • Resistance to smart meters
  • Demand-side management programs