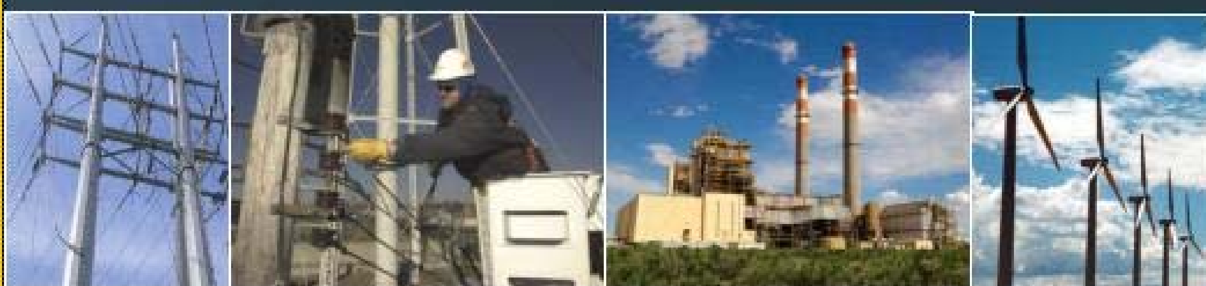

Guide to the Class Cost of Service Study (CCOSS)
Northern States Power Co Electric

I. Overview

Simply stated, the purpose of the Northern States Power Company (NSP) electric Class Cost of Service (CCOSS) is to allocate ***joint*** (e.g.) and ***common*** costs to the designated "classes" of service such as Residential, Non-Demand C&I and Demand C&I. For example, generation capacity costs are "joint" between time periods and overhead costs such as management, are "common" to multiple functions, such as distribution, transmission and generation. The CCOSS also assigns ***direct*** costs (e.g. a dedicated service extensions or dedicated substations), that may be associated with providing service to a particular customer from a specific class of service. The objective of the CCOSS is to make these cost ***allocations*** and ***assignments*** based on identifiable service requirements (e.g. kWh energy requirements and kW capacity requirements), which are the drivers of the costs.

The two basic types of costs are; (1) capital costs associated with investment in generation, transmission and distribution facilities and (2) on-going expenses such as fuel used to produce the energy, labor costs and numerous other operating expenses. The end result is an allocation of the total utility costs (i.e. the revenue requirements) to customer classes according to each class' share of the capacity, energy and customer service requirements.

II. Major Steps of the Class Cost of Service Study

A class cost of service study begins with a detailed documentation of the numerous budgetary elements of the total revenue requirement for the jurisdiction in question. The detailed jurisdictional revenue requirements are the data inputs to the CCOSS. At a high level, the CCOSS process consists of the following three (3) basic steps:

1. <u>Functionalization</u> – The identification of each cost element as one of the basic utility service "functions" (e.g. generation, transmission, distribution and customer).
2. <u>Classification</u> – The classification of the functionalized costs based on the billing component/determinant that each is associated with (e.g. kWs of capacity, kWhs of energy or number of customers).
3. <u>Allocation</u> – The allocation of the functionalized and classified costs to customer classes, based on each class' respective service requirements (e.g. kWs of capacity, kWhs of energy and the number of customers, expressed in terms of a percentage of the total jurisdiction requirement).

III. Step 1: Functionalization

Functionalization is the process of associating each of the numerous detailed elements of the total revenue requirement with functions (and sometimes sub-functions) of the electric utility system. Costs must be first functionalized because each class' service requirement tends to have different relative impacts on each service function. As such, it is necessary to develop separate sub-parts of the total revenue requirement for each function (and sometimes sub-function). The four basic functions and the associated sub-functions are shown in the table below:

Function	FERC Accounts	Sub-Function	Description
Generation	120, 310-346, 500-557	"Energy-related"	Includes the fixed costs of generation plant investment and purchase capacity costs, which have been stratified as "energy-related."
		Summer "capacity-related."	Includes the fixed costs of generation plant investment and purchase capacity costs stratified as "capacity-related" and which are associated with the system summer peak load requirements.
		Winter "capacity-related."	Includes the fixed costs of generation plant investment and purchase capacity costs stratified as "capacity-related" and which are associated with the system winter peak load requirements.
		On-Peak Energy	Includes costs for fuel and purchases of energy for on-peak hours.
		Off-Peak Energy	Includes costs for the fuel and purchases of energy for off-peak hours.
Transmission	350-359, 560-579	None	Includes costs of transmission lines and associated substation facilities used to transport power from its origin generation stations or delivery points to the high voltage side of the distribution substations.
Distribution	360-368, 580-598	Distribution Substations	Includes costs of the facilities (e.g. transformers and switch gear) between the transmission and distribution systems.
		Primary Distribution System "Capacity."	Includes costs of the "capacity" portion (as distinguished from the "customer" portion) of primary voltage conductors, transformers and related facilities.
		Secondary Distribution System "Capacity."	Includes costs of the "capacity" portion (versus "customer" portion) of secondary voltage conductors, transformers, customer services and related facilities.
Customer	360-369, 580-598, 901-916	"Customer" portion of the Primary and Secondary Systems	Includes costs for the "customer" portion of primary and secondary conductors, transformers, customer service drops, related facilities and the costs of metering.
		Energy Services	Includes costs for meter reading, billing, customer service and information, and back office support.

A. Generation Cost Stratification

Stratification is the term used to identify the part of the CCOSS process used to separate or "stratify" fixed generation costs into the necessary "capacity-related" and "energy-related" sub-functions. The "capacity-related" portion of the fixed costs of owned generation (and also of the purchased power contract costs) is based on the percent of total fixed costs of each generation type that is equivalent to the cost of a comparable peaking plant (the generation source with the lowest capital cost). The percent of total generation costs that exceeds the cost of a comparable peaking plant are sub-functionalized as "energy-related." This second portion of the fixed generation costs is "energy-related" because these costs are in excess of the "capacity-related" portion and as such were not incurred to obtain capacity but rather were incurred to obtain the lower cost energy that such plants can produce.

For example, the plant stratification analysis used in the current rate case is shown in the table below. It compares the then current-dollar replacement costs of each plant type, to develop stratification percentages.

Plant Type	$/kW	Capacity Ratio	Capacity %	Energy %
Peaking	$792	$792 / $792	100%	0%
Nuclear	$4,146	$792 / $4,146	19.1%	80.9%
Fossil	$2,022	$792 / $2,022	39.2%	60.8%
Combined Cycle	$1,037	$792 / $1,037	76.3%	23.7%
Hydro	$5,601	$792 / $5,601	14.1%	85.9%
Wind	$20,319	$792 / $20,319	3.9%	96.1%

This process of "stratifying" the revenue requirements of the generation plant is accomplished by applying these stratification percents to each component of the revenue requirements (e.g. book investment, accumulated depreciation, net plant, cost of capital, income taxes, etc.), for each generation plant type.

B. Summer/Winter Split of Generation Capacity-Related Costs

Once the "capacity-related" portion of generation plant costs has been quantified, they are further separated into summer and winter sub-functions. The seasonal sub-function portions are determined as follows.

First, the 12 monthly System peak loads are grouped into a 4-month summer (June, July, August and September) and an 8-month winter seasons. Second, the average hourly load for the year is subtracted from each monthly peak. Third, the remaining monthly excess loads are averaged for each season and the ratio of these two average seasonal "excess" loads is used to assign the "capacity- related" portion of fixed generation costs to the seasons. This calculation for the current rate case is shown below.

(1)	(2)	(3)	(4) = (3) minus 5,155
Month	**Season**	**Monthly NSP System Peak Load**	**Monthly Peak in Excess of Average Hourly Load**
Jan	Winter	6,674	1,519
Feb	Winter	6,349	1,194
Mar	Winter	5,993	838
Apr	Winter	5,659	504
May	Winter	6,281	1,126
Jun	Summer	8,013	2,858
Jul	Summer	9,310	4,155
Aug	Summer	9,524	4,369
Sep	Summer	8,481	3,326
Oct	Winter	6,013	858
Nov	Winter	6,195	1,040
Dec	Winter	6,819	1,664
		6,674	1,519
Average Annual Load		**5,155**	
Average Monthly Excess			
Average of Summer Months			3,677
Average of Winter Months			1,093
Total			4,771
Summer Percent			**77.08%** = 3,677/4,771
Winter Percent			**22.92%** = 1,093 / 4,771.

As shown above 77.08% of generation capacity costs were assigned to the summer season while 22.92% were assigned to winter, thereby separating total generation capacity-related costs into summer and winter seasons.

IV. Step 2: Cost Classification

The second step in the CCOSS process is to classify the functionalized costs as being associated with a measurable customer service requirement which gives rise to the costs. The three principle service requirements or billing components are:

1. Demand – Costs driven by the customer's maximum kilowatt ("kW") demand.
2. Energy – Costs driven by the customer's energy or kilowatt-hours ("kWh") requirements.
3. Customer – Costs that are related to the number of customers served.

The table below shows how each of the functional and sub-functional costs was classified:

Function/Sub-Function	Cost Classification		
	Demand	Energy	Customer
Summer Capacity-Related Fixed Generation	X		
Winter Capacity-Related Fixed Generation	X		
Energy-Related Fixed Generation	X		
Off-Peak Energy (Fuel and Purchased Energy)		X	
On-Peak Energy (Fuel and Purchased Energy)		X	
Transmission	X		
Distribution Substations	X		
Primary Lines	X		X
Primary Transformers	X		
Secondary Lines	X		X
Secondary Transformers	X		X
Service Drops	X		X
Metering			X
Energy Services			X

As shown in the table above, primary lines, secondary lines, secondary transformers and service drops are classified as both "demand" and "customer" related costs. Costs of these sub-functions are driven by **both** the number of customers on the distribution system and the capacity requirements they place on the system. The analysis used to separate these costs into demand and customer components is called the Minimum Distribution System (MDS) method.

The Minimum Distribution System method involves comparing the cost of the minimum size of each type of facility used, to the cost of the actual sized facilities installed. The cost of the minimum size facilities determines the "customer" component of total costs and the "capacity" cost component is the difference between total installed cost and the minimum sized cost.

The table also shows the percent of each cost element that was classified as "customer" related based on the most recent Minimum System study.

Equipment Type	% Classified as "Customer" Related
Overhead Lines Primary	42.3%
Primary Transformers	0.0%
Overhead Lines Secondary	54.9%
Underground Lines Primary	85.9%

Underground Lines Secondary	54.3%
Line Transformers Secondary	48.8%
Services	72.7%

V. Step 3: Cost Allocation to Customer Class (Assignment of Costs to Customer Classes)

The third step in the CCOSS process is allocation, which is the process of assigning (allocating or directly assigning) functionalized and classified costs to customer classes. Generally, cost assignment occurs in one of 2 ways:

- Direct Assignment - A small but sometimes important portion of costs can be directly assigned to a specific customer of a particular customer class, because these costs can be exclusively identified as providing service to a particular customer. Examples of costs that are directly assigned include:
  - Customer-dedicated transmission radial lines or dedicated distribution substations
  - Street lighting facility costs
- Allocation - Most electric utility costs are incurred in common or jointly in providing service to all or most customers and classes. Therefore, allocation methods have to be developed for each functionalized and classified cost component. The allocation method is based on the particular measures of service that is indicative of what drives the costs.
  - Class allocators (sometimes called allocation strings) are simply a "string" of class percentages that sum to 100%.
  - There are 2 types of allocators:
    - External Allocators –These are the more interesting allocators that are based on data from outside the CCOSS model (e.g. load research data, metering and customer service-related cost ratios). In general, there are three types of external allocators:
      - Capacity –related (sometimes referred to as Demand) allocators such as:
        - System coincident peak (CP) responsibility or class contribution to system peak (1CP, 4CP or 12CP)
        - Class peak or non-coincident peak
        - Individual customer maximum demands
      - Energy-related allocators such as:
        - kWh at the customer (kWh sales)
        - kWh at the generator (kWh sales plus loses)
        - kWh energy, weighted by the variable cost of the energy
      - Customer-related allocators
        - Number of customers
        - Weighted number of customers, where the weights are based on cost of meters, billing, meter-reading, etc.

      Details on the external allocators used in the CCOSS model are shown in Appendix 1.

    - Internal Allocators – These are allocators based on combinations of costs already allocated to the classes using external allocators. These internal allocators are used to assign certain costs, which are most appropriately associated with and assigned to classes by some combination of other primary service requirements, such as kWs demand, kWhs of energy or the number of customers. Examples of internal allocators include:

- PTD – Production, transmission and distribution plant investment.
- OXDTS – Distribution O&M expenses without supervision and miscellaneous expenses.

Details on the development of the internal allocators used in the CCOSS model are shown in Appendix 2.

VI. Customer Class Definitions

Ideally, there would be no customer class groupings and cost allocation would reflect the unique costs of each individual customer. Because this is not possible, it is necessary to develop a cost study process that identifies costs of service for groups of customers ("classes") where the customers of the class have similar cost/service characteristics. The basic classes of service employed in the Company's CCOSS are the following:

1. Residential
2. Non Demand Metered Commercial
3. Demand Metered Commercial & Industrial and
4. Street & Outdoor Lighting

Also, because of the significantly different distribution-functional requirements of customers within the Demand Metered C&I class, the Company's CCOSS also identifies the cost differences associated with the following distribution-function requirements within this class:

1. Secondary
2. Primary
3. Transmission Transformed
4. Transmission

More detail on customer class definitions is shown in Appendix 3.

VII. CCOSS Data Inputs

As noted earlier, there are a large number of inputs to the CCOSS model including detailed rate base and expense items from the Jurisdictional Cost of Service Study (JCOSS) as well as numerous inputs from other sources used to develop external allocators.

VIII. Organization of the CCOSS Model

The CCOSS model consists of numerous worksheets which show costs by customer class in Total (as shown on the worksheet tab labeled "TOT") and at the following more detailed levels including Billing Unit, Function and Sub-function as shown below:

1. Billing Unit:

   a. Customer (Cus)

b. Demand (Dmd)
c. Energy (Ene)

2. Function and Associated Sub-Function:

   a. Energy (Ene)
      a) On-Peak Energy (On)
      b) Off-Peak Energy (Off)

   b. Generation (Gen_Dmd): Sub-functions include:
      a) Summer Capacity-Related Plant (Summ)
      b) Winter Capacity-Related Plant (Wint)
      c) Energy-Related Plant (Base)

   c. Transmission (Transco)

   d. Distribution (Disco): Sub-functions include:
      a) Distribution Substations (Psub)
      b) Primary Voltage? (Prim)
      c) Secondary Voltage? (Sec)

   e. Customer (Cus): Sub-functions include:
      a) Service Drops (Svc_Drop)
      b) Energy Services (En_Svc)

In the CCOSS spreadsheet there is a separate worksheet tab for each of the above billing units, functions and sub-functions. The label for each worksheet tab is show in parentheses above. This multi-level breakdown of costs is useful for designing rates as well as for determining class revenue responsibilities.

IX. CCOSS Calculations

Listed below are important calculations that are part of the CCOSS model. These calculations occur at the "TOT" layer of the CCOSS as well as each of the "sub-layers" for each billing component, function and sub-function. Showing results at the more detailed billing component, function and sub-function levels is important for rate design purposes, as well as other analyses such as the development of voltage discounts.

A. Rate Base Calculation

Rate Base = Original Plant in Service – Accum. Depr + CWIP + Other Additions

The above rate base calculation occurs on "TOT" layer as well as each function/sub-function layer.

B. Revenue Requirements Calculation (Class Cost Responsibility)

The Revenue Requirements Calculation (sometimes referred to as the "Backwards Revenue Requirement Calculation) is used to calculate "**cost"** responsibility for each customer class. This has to be done within the CCOSS model because the JCOSS model does it only at the total jurisdiction level, not by class. The class "**cost"** responsibility is based on the same return on rate base for each class that is equal to the overall proposed rate of return. In other words, class revenues requirements are calculated to provide the same return on rate base for each customer class. This calculation occurs on the "TOT" layer as well as for each function, sub-function and billing component after all expenses and rate base items have been allocated. As such, class cost responsibility is available for each function, sub-function and billing component. This analysis serves a starting point for rate design. The formula is shown below:

Retail Revenue Requirement = Expenses (including off-setting credits from Other Operating Revenues)
+
(Return on Equity x Rate Base) x 1 / (1-Tax Rate)
+
(Tax Additions – Tax Deductions) x Tax Rate / (1-Tax Rate)
+
AFUDC

Where:

Expenses = O&M + Book Depreciation + Real Estate & Property Tax + Payroll Tax + Net Investment Tax Credit – Other Retail Revenue – Other Oper. Revenue

Tax Additions = Book Depreciation + Deferred Inc Tax + Net Inv Tax Credit + Other Misc Expenses.

Tax Deductions = Tax Depreciation + Interest Expense + Other Tax Timing Diff

C. Total Return and Return on Rate Base (Based on Class Revenue Responsibility)

After rates have been designed and each class' "**revenue"** responsibility has been determined, the model calculates total return and return on rate base using the following formulas. These calculations are performed at both present and proposed rate levels.

Total $ Return = Revenue – O&M Expenses – Book Depr.
– Real Estate & Property Taxes– Provision for Deferred Inc Taxes – Inv. Tax Credits
– State & Federal Income Taxes + AFUDC

Percent Return on Rate Base = Total $ Return / $ Rate Base

After rates have been designed, the return on rate base is typically different for each customer class. In other words, the resulting class "**revenue"** responsibility differs from class "**cost"** responsibility.

XI. CCOSS Output

The filed output of the CCOSS model includes the "Tot" worksheet layer of the much larger model. The important output from the functional, sub-functional and billing component layers is presented on page 2 of this "TOT" layer. The following table lists what is shown on each CCOSS page when printed.

Final CCOSS Printout "Tot" Worksheet			
CCOSS Section	**Page Number**	**Results Detail**	**Line Numbers**
Results Summary	1	Rate Base Summary	1-22
		Income Statement Summary	23A-32B
		Proposed Cost Responsibility at Equal ROR (the cost of service) compared to **Proposed** Rate **Revenue** Responsibility	33-45
	2	**Proposed Cost** Responsibility at Equal ROR (the cost of service) compared to **Present** Rate **Revenue** Responsibility	1-50
Rate Base Detail	3	Original Plant in Service	1-53
	4	MINUS Accumulated Depreciation	1-28
		MINUS Accumulated Deferred Income Tax	29-56
	5	PLUS Construction Work in Progress & Other Additions	1-35
		EQUALS Total Rate Base	36
Income Statement Detail	6	Present, Proposed and Equal Revenues	1-25A
		MINUS O&M Expenses part 1	26-40
	7	MINUS O&M Expenses part 2	1-34
	8	MINUS Book Depreciation	1-25
		MINUS Real Estate & Property Taxes	26-53
	9	MINUS Provision for Deferred Income Tax	1-28
		MINUS Investment Tax Credit	29-55
		EQUALS Present,, Proposed and Equal Operating Income Before Income Taxes	58A, 58B & 58C
	10 (Income Tax Calcs.)	Tax Additions	33-43
		MINUS Tax Deductions	1-32
		EQUALS Total Tax Adjustments	44
		PLUS Present, Proposed & Equal Operating Income Before Income Taxes	FROM Page 10 58A, 58B & 58C
		EQUALS Present and Proposed Taxable Income	45A, 45B & 45C
		MULTIPLIED BY State and Federal Tax Rates	
		EQUALS Present, Proposed and Equal State and Federal Income Taxes	46A, 46B & 46C
	10 (Total Return Calcs.)	Present, Proposed and Equal Operating Income Before Income Taxes	FROM Page 10, Rows 58A, 58B & 58C
		MINUS Present, Proposed and Equal State and Federal Income Taxes	46A, 46B & 46C
		EQUALS Present and Proposed Preliminary Return	47A, 47B & 47C
		PLUS AFUDC (from page 12)	48
		EQUALS Present, Proposed and Equal Total Return	49A, 49B & 49C

XI. CCOSS Output (continued)

CCOSS Section	Page Number	Results Detail	Line Numbers
Misc Calcs	11	AFUDC	1-26
		Labor Allocator	27-48
Allocator Data	12	Internal Allocators and Associated Data	1-39
	13	External Allocators and Associated Data	1-52