BUILDING A WORLD OF DIFFERENCE®

NEW YORK INDEPENDENT SYSTEM OPERATOR

Rate Schedule 1 Study

Final Report

July 2011

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1.0 INTRODUCTION

The New York Independent System Operator (NYISO) initiated an independent evaluation of the Rate Schedule 1 (RS-1) charges and current rate structure. NYISO hired Black & Veatch Corporation (Black & Veatch or B&V) to perform the analysis with the requirement to work with the Budget and Priorities Working Group (BPWG) to gain input from the Market Participants (MPs). Black & Veatch began the analysis in January 2011 and has interviewed NYISO department representatives, surveyed MPs, and provided status updates to the BPWG during the course of the project.

The following report presents Black & Veatch's initial, preliminary, independent recommendations.

1.1 Scope of Services

The Black & Veatch project team has performed the following tasks in developing the recommendation for Rate Schedule 1:

1. Compare the methodologies and allocation percentages for recovering annual budget costs and FERC fees of PJM, ISO-NE, MISO, CAISO, ERCOT, and Southwest Power Pool
2. Meet with Market Participants from each sector and administer a survey to gather relevant facts, context, background, and concerns regarding the current Rate Schedule 1 cost allocation methodology.
3. Evaluate NYISO's markets and operations to identify reasonable parameters for allocating the costs of Client's annual budget to Market Participants.
4. Identify discrete product or service categories with distinct characteristics that could be used as a basis for allocating NYISO's costs.
5. Determine the billing determinants assigned to each product or service category identified.
6. Illustrate the impacts of any proposed alternative bases for allocating NYISO's costs on each sector of Market Participants.
7. Evaluate NYISO's budgets to allocate, if recommended, the specific costs appropriate to be recovered from each of the groups/classes of Market Participants causing or benefiting from activity in each respective product or service category.

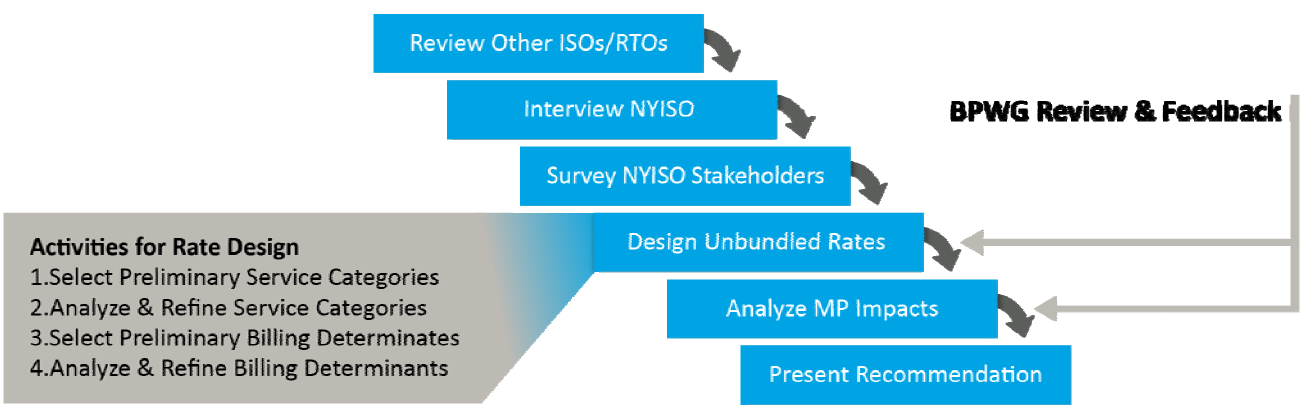

Figure 1-1 Project Scope

8. Evaluate NYISO's FERC fees to allocate, if recommended, the specific costs appropriate to be recovered from the each of the groups/classes of Market Participants causing or benefiting from activity in each respective product or service category.
9. Recommend a revised Rate Schedule 1 allocation basis/methodology, if the Consultant determines that revisions are warranted based on its performance of the Services, and supporting this recommendation with supporting facts and evidence.

2.0 EXECUTIVE SUMMARY

The purpose of this report is to provide Black & Veatch's independent observations and recommendations related to the following:

- The identification of an unbundled list of products or services provided by the NYISO that might be separately priced based on costs and benefits
- The use of a 2011 budget year and a five-year average from 2007 – 2011 as test periods to develop a cost of service study that determines cost functionalization, classification and allocation for each service or product identified
- The evaluation of the current split of costs between load and supply to determine if that split remains reasonable based on the cost of service study test
- The evaluation of the robustness of the current cost study based analysis of historical years costs
- The identification of appropriate billing determinants for unbundled products or services
- The development of proposed rate or rates for the recovery of NYISO costs currently recovered under RS-1
- Rate structures and cost recovery methodologies used by other RTO/ISO
- The final recommendation related to use of an unbundled rate schedule or continuation with the current RS-1 rate with or without modification of the cost split between load and generation.

After considerable analysis and scenario-testing, we found that while there were different results associated with each of a number of alternative allocation scenarios, the effective cost splits between load generation, supply, and non-physical fell between 75% / 19% / 6% and 60% / 34% / 6%. When excluding the non-physical market allocation, the effective load/supply split of these scenarios is 80% / 20% and 63% / 37%. In our opinion, and for reasons discussed in the report, each of the scenarios bounds the upper and lower limit of what is a reasonable cost allocation based on the principles of cost causation and benefits received. The midpoint of the two cost studies is 67% / 27% / 6%. When excluding the non-physical market transactions, the effective split between load and supply (using the midpoint of the two scenarios) is 72% / 28%.

Black and Veatch recommends that the RS-1 rate continue to be billed on a bundled basis, with a percentage split of costs among load, supply, and non-physical markets approximately equal to the mid point between the results of the two cost studies. The current procedure of rebating all revenue collected from non-physical markets to physical injections and withdrawals on a monthly basis is appropriate for continued use. The ratio of the rebate between load and supply should be the ratio that results from this study. We further recommend that a true up provision be added to the rate that assures timely recovery of the actual budget dollars approved for each year including any approved adjustments to the budget resulting from extraordinary circumstances. We reach this conclusion as discussed in detail below based on the input of stakeholders and NYISO Staff; a review of RTO/ISO cost recovery mechanisms; an independent cost of service analysis for the 2011 budget test year and a five-year average test period; and other factors discussed in detail in the report. We believe the cost of service results are robust based on the historic annual costs for the NYISO.

Finally, as we discuss in this report, there is no single definitive cost of service study scenario that we have relied on for our conclusions. Generally, we have directly assigned costs wherever possible and then used two different methods for allocation of shared service costs to bound the outcomes of our cost of service work. This resulted in the two afore-mentioned scenarios. Ultimately, if bundled rates are to be continued, we recommend a change from the current 80/20 split to a split that is at or around the midpoint of 72/28. We find that the upper and lower bounds of the studies represent the limits of what would be reasonable, and therefore recommend a split near the midpoint as a reasonable settling point.

While Black & Veatch supports the continued use of a bundled rate for the recovery of Rate Schedule 1, we also have presented the unbundled rates that would be implemented, should the NYISO and the Market Participants choose to do so. The recommended unbundled rates are shown in Table 5-11, and represent the midpoint of the two cost studies.

Based on the results of the cost allocation study, we recommend that FERC expenses be allocated in the same ratio of load, supply, and non-physical. We reach this conclusion based on the fact that FERC expenses represent a corporate overhead expense that, had they been included in the budget used for our cost of service study, would have been shared in an approximately similar proportion to the results of the overall study.

3.0 RATE STRUCTURES AT OTHER ISO'S/RTO'S

System Operators in the United States reflect varying stages of cost unbundling in the rates they charge to their respective market participants. For comparative purposes, Black & Veatch reviewed the rate structures for ISO New England (ISO-NE), PJM, California ISO (CAISO), ERCOT, Midwest ISO (MISO) and Southwest Power Pool (SPP). The current rate designs at ISOs/RTOs vary from a fully bundled single rate (ERCOT) to the multiple schedules used by California ISO. Each of the ISO/RTOs has attempted to involve stakeholders, to varying degrees, while developing new rate changes. A brief description of their rates is shown below. All capitalized terms have the same meaning as that stated in their tariffs.

3.1 Summary of Cost Recovery from Load and Supply

The following table summarizes the approximate cost recovery ratio from load and supply. Generally, the more unbundled the rates are (CAISO), the higher percentage of cost are recovered from supply. The most bundled rates (ERCOT and SPP) have the highest percentage of costs recovered from load.

Table 3-1
Summary of Cost Recovery from Load and Supply (1)

Company	Load Share %	Supply Share %
ERCOT	100%	0%
Southwest Power Pool	100%	0%
New York ISO (2)	80%	20%
PJM	79%	21%
ISO-New England	78%	22%
Midwest ISO	75%	25%
California ISO	67%	33%

Notes:
(1) Approximate current ratio based on contact with RTO/ISO staff and available published documents
(2) NYISO varies somewhat based on collections for TCCs, Virtuals, and Demand Response. The 2011 budget includes an assumption that approximately $9M in recoveries from participants in the non-physical TCC, Virtual and Demand Response markets will be rebated to physical load and supply for a net Rate Schedule 1 allocation of 75% to load, 19% to supply and 6% to non-physical markets.

3.2 PJM

The PJM tariffs were developed in a collaborative process with a group of market participants. However, the ultimate approved tariffs resulted from settlement discussions initiated after the initial FERC application. The current PJM schedules include:

3.2.1 Schedule 9-1 - Control Area Administration Service

Control Area Administration Service comprises all of the activities of PJM associated with preserving the reliability of the PJM Region and administering Point-to-Point Transmission Service and Network Integration Transmission Service. PJM provides Control Area Administration Service to customers using Point-to-Point or Network Integration Transmission Service under this Tariff.

PJM charges each user of Control Area Administration Service a monthly charge equal to the Monthly Control Area Administration Service Rate of $0.1750 per MWh times the total quantity in MWhs of energy delivered (including losses) during a month.

3.2.2 Schedule 9-2 - FTR Administration Service

FTR Administration Service comprises all of the activities of PJM associated with administering the Financial Transmission Rights (FTR) provided for under Attachment K to the Tariff, including, but not limited to, coordination of FTR bilateral trading, administration of FTR auctions, support of PJM's on-line, Internet-based eFTR tool, and analyses to determine what total combination of FTRs can be outstanding and accommodated by the PJM system at a given time. PJM provides this service to entities that hold FTRs or entities that submit offers to sell or bids to buy FTRs.

PJM charges each user of Financial Transmission Rights Administration Service each month a charge equal to:

(i) The FTR Service Rate, $0.0026 per MWh, times the quantity in megawatts of all FTRs held by the user in each hour of the month, summed for each hour that the user holds FTRs during the month and time period the FTR is in effect; plus

(ii) The FTR Service Rate, $0.0018 per hour, times the sum of (1) the number of hours in all bids to buy Financial Transmission Rights Obligations submitted by the user during the month, plus (2) five times the number of hours in all bids to buy Financial Transmission Rights Options submitted by the user during each month.

3.2.3 Schedule 9-3 - Market Support Service

Market Support Service comprises all of the activities of PJM associated with supporting the PJM Interchange Energy Market and related functions, as described in Schedule 1 of the Operating Agreement and the Appendix to Attachment K to the Tariff, including, but not limited to, market modeling and scheduling functions, locational marginal pricing support, market settlements and billing, support of PJM's Internet-based customer interactive tool known as eSchedules, and market monitoring. PJM provides this service to customers using Point-to-Point or Network Integration Transmission Service, Generation Providers and entities that submit offers to sell or bids to buy energy in the PJM Interchange Energy Market.

PJM charges each user of Market Support Service each month a charge equal to the sum of:

(i) The MS Service Rate, $0.0386 per MWh times (1) the total quantity in MWhs of energy delivered to load (including losses and net of operating Behind The Meter Generation, but not to be less than zero) in the PJM Region or for export from the region during the month by Point-to-Point Transmission Service or Network Integration Transmission Service customers, plus (2) the total quantity in MWhs of energy input into the Transmission System by a Generation Provider plus (3) the total quantity in MWhs of all accepted Increment Bids and Decrement Bids submitted by the customer during the month; plus

(ii) The MS Service Rate Component 2, $0.0577 per Bid/Offer Segment times the number of Bid/Offer Segments submitted by the user during the month.

3.2.4 Schedule 9-4 - Regulation and Frequency Response Administration Service

Regulation and Frequency Response Administration Service comprises all of the activities of PJM associated with administering the provision of Regulation and Frequency Response Service under Schedule 3 of the Tariff. PJM provides this service to Load Serving Entities and to generators that provide regulation in accordance with Schedule 3.

PJM charges each user of Regulation and Frequency Response Administration Service each month a charge equal to the Regulation and Frequency Response Administration Service Rate, $0.2349 per MWh times the MWhs of the user's hourly regulation objective as a Load Serving Entity determined pursuant to Schedule 3, plus the MWhs of regulation scheduled (including self-scheduling) from generating units owned by the user, summed for each hour in the month.

3.2.5 Schedule 9-5 - Capacity Resource and Obligation Management Service

Capacity Resource and Obligation Management (CROM) Service comprises the activities of PJM associated with (i) assuring that customers have arranged for sufficient generating capacity to meet their unforced capacity obligations under the Reliability Assurance Agreement (RAA); (ii) processing Network Integration Transmission Service; (iii) administering the Reliability Pricing Model auctions for the PJM Region; and (iv) administering or providing technical support for the RAA (as delegated to PJM under the RAA), including, but not limited to, long-term load forecasting, studies to establish reserve requirements, and the determination of each Load-Serving Entity's capacity obligations. PJM's eCapacity Internet-based tool enables many of these functions. PJM provides this service to Load-Serving Entities and to owners of Capacity Resources.

PJM charges each Load-Serving Entity in the PJM Region a monthly charge equal to the Capacity Resource and Obligation Management Service Rate, $0.0894 per MW-day, times the summation for each day of the month of the Daily Unforced Capacity Obligation of each user.

3.2.6 PJM Cost Recovery From Load and Supply

The following table shows the percentage of PJM's revenue requirement that is recovered from each rate, as well as billing determinants used and the whether the charges are recovered from load, supply, or both.

Table 3-2
PJM Cost Recovery

Rate	Percent of Revenue Requirement	Load	Supply	Billing Determinants
9-1 Control Area Administrative Service	58%	100%	0%	MWh of load
9-2 FTR Service	5%	50%	50%	MWh of FTRs held
9-3 Market Support Service	30%	50%	50%	MWh of load and gen
9-4 Regulation & Frequency Response Administration	2%	50%	50%	MWh of hourly regulation required and provided
9-5 Capacity Resource & Obligation Management	5%	50%	50%	MW days of capacity required and provided
Composite Percentage		**79%**	**21%**	

Source: Suzanne Daugherty, PJM CFO, input per PJM Tariff Schedules 9-1 through 9-5

3.3 ISO-New England

The ISO-New England (ISO-NE) Tariffs were developed by ISO-NE and then modified based on Settlement discussions before FERC.

ISO-NE has three separate rate schedules (as listed below) designed to recover the ISO-NE's operating costs on a forecast basis, based on its annual budget, with a true-up mechanism to ensure no over or under recovery of the ISO-NE's actual operating expenses. The basic rate design was implemented in 1999. Below is the brief description of three rate schedules contained in the ISO tariff.

3.3.1 Schedule 1 – Scheduling, System Control and Dispatch Service

Scheduling, System Control and Dispatch Service is the service required to schedule at the regional level the movement of power through, out of, within, or into the New England Control Area. For regional transmission service under the Tariff, Scheduling Service is an Ancillary Service that can be provided only by the ISO. This schedule provides for the assessment of charges designed to recover the ISO-NE's costs associated with performing administrative functions and tasks relating to scheduling transmission service and dispatching the transmission system. These ISO's expenses are based on the functions and activities required to provide this service and include:

- Processing and implementation of requests for transmission service, including support of OASIS Node
- Coordination of transmission system operation, including administration of reactive power requirements and implementation of necessary control actions by the ISO and support for these functions
- Billing associated with regional transmission services provided under the tariff
- Transmission System Planning
- Administrative support for the above tasks and functions

The Schedule 1 rates are as follows:

a) Each Customer that is obligated to pay the Regional Network Service rate will pay each month the product of $0.12683 per kilowatt month times its regional Monthly Network Load for that month;
b) Each Customer that is a Transmission Customer receiving Through or Out Service shall pay each month the product of the Transmission Customer's highest amount of Reserved Capacity (expressed in kilowatts) for an hour for each transaction scheduled to occur during the month as Through or Out Service multiplied by $0.00017 per kilowatt for each hour of service.

3.3.2 Schedule 2 – Energy Administration Service

This schedule provides for the assessment of charges designed to recover the ISO-NE's costs associated with administering the Energy Market. The functions and tasks performed by the ISO-NE include:

- Core operation of the Energy Market
- Generation and demand dispatch related to the Energy Market
- Energy Accounting
- Loss determination and allocation
- Billing preparation
- Market power monitoring and mitigation for the Energy Market
- Sanction activities
- Operation of Financial Transmission Rights (FTR) auctions
- Market assessments and reports
- Formulation of additional Market Rules and proposals to modify existing rules.

Each Market Participant that has an account for Energy that is settled by the ISO will pay a monthly amount based on Energy Transaction Units (TUs), Increment Offers, Decrement Bids, Volumetric Measures, submitted FTR auction bids, and cleared FTR auction bids.

1. Energy TU Based Charges: Each customer will pay sum of the products of:
   a. $0.55449 times the Customer's first 12,500 Energy TUs for that month; plus
   b. $0.50408 times the amount of Energy TUs that exceed 12,500 but are less than or equal to 39,500; plus
   c. $0.45367 times the amount of Energy TUs that exceed 39,500.

2. Charges Based on Increment Offers and Decrement Bids: Each Customer submitting Increment Offers and/or Decrement Bids will pay, amounts equal to:
    a. $0.00500 times the number of Increment Offers and Decrement Bids submitted by the Customer for that month; plus
    b. $0.06000 times the number of Increment Offers and Decrement Bids submitted by the Customer for that month that clear in the Day-Ahead Energy Market.
3. Volumetric Measure (VM) Based Charges: A Customer shall be considered an Energy Administration Service (EAS) VM Customer if the sum of Monthly Real-Time Load Obligation and Monthly Real-Time Generation Obligation (measured in megawatt hours, MWh) assessed to that Customer during the month exceeds zero, in which case, the total EAS VM charges for that Customer will be equal to the sum of:
    a. Monthly Real-Time Load Obligation (MWh); and
    b. Monthly Real-Time Generation Obligation (MWh); provided, however, that Monthly Real-Time Generation Obligation associated with energy imported into the New England Control Area by Bangor Hydro-Electric Company across the New Brunswick Ties shall be excluded (up to 300 MW) for billing and rate calculation purposes from EAS VMs.
4. Each Market Participant that is identified as an EAS VM Customer for that month shall pay an amount, in arrears, based on total EAS VM, equal to:
    a. $0.19333 per MWh for the first 250,000 MWh of EAS VM for that month; plus
    b. $0.17575 per MWh for each VM that exceeds 250,000 EAS VM but is less than or equal to 1,500,000 MWh for that month; plus
    c. $0.15818 per MWh for each EAS VM in excess of 1,500,000 MWh for that month.
5. Charges Based on Submitted and Cleared FTR Bids: Each Customer submitting FTR auction bids will pay, amounts equal to:
    a. $0.60724 times the number of bids submitted by the Customer into any FTR auctions held for that month; plus
    b. $0.60724 times the number of bids submitted by the Customer into any annual or multi-month FTR auctions; plus
    c. $1.07903 times the number of bids submitted by the Customer during that month that clear any FTR auctions held for that month; plus
    d. $1.07903 times the number of bids submitted by the Customer that clear any annual or multi-month FTR auctions.

3.3.3 Schedule 3 – Reliability Administrative Service (RAS)

This schedule provides for the assessment of charges designed to recover the ISO-NE's costs associated with administration of the Reliability Markets. The functions and tasks performed by the ISO-NE include:

- Generation Dispatch associated with Reliability Markets
- Reliability Markets accounting
- Billing preparation
- The ISO generation emissions analysis
- Risk profile updates
- Triennial review of resource adequacy
- Studies and qualification of resources under Forward Capacity Market
- Preparation of regional reports and load forecasts and profiles
- Support of power supply, environmental and market reliability planning activities
- Market power monitoring, mitigation and assessment of the Reliability Markets
- Formulation of additional Market Rules and proposals to modify existing rules

Each Transmission Customer taking Through or Out Service that is not a Market Participant will be considered a RAS Customer and will pay each month, a RAS fee equal to the product of $2.39 times the number of hourly Through or Out reservations made for that month.

Each Customer that is a Market Participant will be considered a RAS Customer and shall pay each month, an amount equal to the product of $0.14078 per kilowatt month times the Market Participant's Real-Time NCP Load Obligation (measured in kilowatts) for that month.

For Exports, each RAS Customer will pay each month, an amount equal to $0.31 per MWh per Export, where MWh represents the hourly scheduled MWs of associated Export.

3.3.4 True-Up Provision

For the Services described in Schedules 1, 2, and 3, deviations between collections and the ISO's actual expenses are reconciled through a year-to-year, prospective true-up. For example, before the close of calendar year 2010, the ISO will compute the total actual-to-date and projected-to-year-end expenses of providing each of those Services, and compare these totals with the total charges actually collected (and projected to be collected through 2010) under the Tariff for each Service during calendar year 2010. From these figures the ISO will calculate rates for calendar year 2011, and make a rate change filing for calendar year 2011 and succeeding years, as required, to reflect the budget amount for the applicable calendar year and the true-ups calculated by means of the analysis and adjustments. Any deviation between projected and actual true-up amounts for calendar year 2010 will be reflected in the rate changes for calendar year 2011.

3.3.5 ISO-NE Cost Recovery From Load and Supply

The following table shows the percentage of ISO-NE's revenue requirement that is recovered from each rate, as well as billing determinants used and whether the charges are recovered from load, supply, or both.

Table 3-3
ISO-NE Cost Recovery

Rate	Percent of Revenue Requirement	Load	Supply	Billing Determinants
Schedule 1 - Scheduling Service	21%	100%		Charged to load: MWh and reserved capacity of the highest hourly amount during the month
Schedule 2 - Energy Administration Service	43%	50%	50%	Charged to load, gen, and FTR's: 15% based on energy, incremental and decremental changes, and FTR bids, 85% based on monthly load and gen. obligation
Schedule 3 - Reliability Administration Service	36%	100%		Charged to withdrawals: MWh of peak load and exports
Composite Percentage		**78%**	**22%**	

Source: ISO-NE 2009 FERC Form 1 and CAISO 2012 Cost of Service Study, p. 38

3.4 California ISO

Originally, the California ISO (CAISO) proposed the first charge to recover its cost of operations in a filing made on October 17, 1997 in Docket No. ER 98-211-000. The original Grid Management Charge (GMC) was a bundled formula rate. Following a settlement with stakeholders that extended the bundled rate through 2000 and gave rise to a stakeholder process to unbundle the GMC, the ISO proposed an unbundled GMC on November 1, 2000 that had three service charges: 1) the Control Area Services Charge; 2) Congestion Management (the Inter-Zonal Scheduling Charge); and 3) Ancillary Services (AS) and Real-time Energy Operations (the Market Operations Charge). Each charge was recovered through a volumetric (MWh) rate designed to recover the costs through related customer usage.

CAISO's rates have continued to evolve over time and are the most unbundled of any ISO/RTO rate design. The ISO's current GMC rate design was submitted to FERC in February 2008 and consisted of: 1) the elimination of the Congestion Management Charge; 2) modifications to the Core Reliability Services (CRS) and Energy Transmission Services (ETS) Charges to reflect flows on Transmission Ownership Rights (TORs); 3) changes in the billing determinants for Forward Scheduling (FS) and Market Usage (MU) Charges (including the introduction of the Market Usage-Forward Energy Charge (MUFE)); and 4) an increase in the SMCR Charge from $500 to $1,000. The proposal was approved by FERC on December 18, 2008 and went into effect on April 1, 2009.
CAISO currently has rates defined for the following categories:

- Core Reliability Services (CRS)
- Energy Transmission Services (ETS)
- Transmission Ownership Rights (TOR)
- Forward Scheduling (FS)
- Market Usage (MU)
- Convergence Bidding
- Settlements, Metering, & Client Relations (SMCR).

CAISO GMC Rates for 2011 with effective from January 1, 2011 is shown in Table 1-3.

Table 3-4
CAISO GMC Rates for 2011

#	Type	Rate	Billing Unit	Data
1.	CRS - Demand Charge	$75.8960	MW-mo	Non-coincident Peak - Maximum Hourly load (not including exports) within a month during the hours ending 07 through 22
2.	CRS - Demand Off Peak	$50.0999	MW-mo	Non-coincident Peak - Maximum Hourly load (not including exports) within a month during the hours ending 01 through 06 and 23 and 24.
3.	CRS - Energy Export	$1.6290	MWh	Export MWhs, excluding TOR exports
4.	ETS - NE	$0.2953	MWh	MWhs of Metered Balancing Authority Area Load, excluding TOR Metered Balancing Authority Area Load
5.	ETS - UE	$1.2225	MWh	MWhs of Uninstructed Imbalance Energy summed by interval, excluding PIRP UIE
6.	CRS/ETS-TOR Energy Export	$ 0.2266	MWh	MWhs of TOR Metered Balancing Authority Area Load
7.	Forward Scheduling	$1.3170	Non-zero MW Schedule	Number of Day Ahead and Hour Ahead Scheduling Process Load, Generation, Import, Export and awarded AS energy schedules
8.	Forward Scheduling Inter-SC Trade	$1.3170	Non-zero MW Inter SC trade schedule	Number of interSC trade schedules
9.	Forward Scheduling PGAB Inter-SC Trades	0.9956	Non-zero MW Inter SC trade schedule	Number of PG&E Path 15 Facilitator inter SC trade schedules
10.	MU-Awarded AS	0.4488	MWh	MWhs purchases and sales of AS
11.	MU-Instructed Energy	0.4488	MWh	MWhs of Instructed Energy summed by interval
12.	MU-Net Uninstructed Deviation	0.4488	MWh	MWhs of Uninstructed Imbalance Energy summed by interval, excluding PIRP UIE
13.	MU-Forward Energy	0.0494	MWh	Maximum MWh of an SC's Supply or Demand
14.	Convergence Bidding Fee	0.0050	Per bid segment	per bid segment of submitted convergence bids
15.	Convergence Bidding	0.0618	MWh	MWh of Convergence Bidding
16.	ETS/MU PIRP Deviations	1.6713	MWh	MWhs of Uninstructed Imbalance Energy from Participating Intermittent Resources summed during the month
17.	SMCR	1,000	Customer-month	For customers with non-zero market, PTO, or CRR invoice
Note: 1. The convergence bidding expected to go live on 2/1/11				

3.4.1 True-Up Provision

Each component rate of the Grid Management Charge will be adjusted automatically on a quarterly basis, up or down, so that rates reflect the annual revenue requirement as stated in the CAISO's filing or posting on the CAISO Website if the estimated revenue collections for that component, on an annual basis, change by more than five percent (5%) or $1 million, whichever is greater, during the year. The adjustment may not be implemented more than once per calendar quarter, and will be effective the first day of the next calendar month.

3.4.2 CAISO Cost Recovery From Load and Supply

The following table shows the percentage of CAISO's revenue requirement that is recovered from each rate, as well as billing determinants used and the whether the charges are recovered from load, supply, or both. As shown in the table, the revenue requirement is recovered 67% from Load and 33% from Supply. This is the highest percentage recovered from Supply of all the ISO/RTO's reviewed.

Table 3-5
CAISO Cost Recovery

Function	Rate Name	% of Rev Req	Load	Supply	Billing Determinant
Core Reliability Services (CRS)	CRS - Demand (peak)	17.0%	100%	0%	Monthly on peak NCP
	CRS - Demand (off peak)	0.5%	100%	0%	Monthly off peak NCP
	CRS - Energy export	4.4%	100%	0%	MW of exports, excluding exports on transmission ownership rights (TORs)
Energy Transmission Services (ETS)	ETS - net energy	36.2%	100%	0%	MWh of metered control area load, excluding load on TORs
	ETS - uninstructed deviations	6.2%	0%	100%	MWh of uninstructed imbalance energy (UIE) netted over the settlement interval
Transmission Ownership Rights	TOR	0.5%	100%	0%	MWh of metered control area load on TORs
Forward scheduling (FS)	FS	6.3%	50%	50%	Count of hourly schedules
	FS - interSC trades				Count of hourly trades
Market Usage (MU)	Purchase and sales of ancillary services (AS)	18.1%	0%	100%	Day ahead (DA) and hour ahead scheduling process real time (RT) MWh
	Instructed energy (IE) RT				MWH of IE
	Net uninstructed deviations - RT				MWh of UIE netted over the settlement interval
	Forward energy	8.4%	50%	50%	Maximum MWh of supply or demand scheduled in the DA market
Convergence bidding	Bid charge	1.5%	50%	50%	Bid charge of $0.005 per bid segment
	Volumetric charge				Gross amount of supply or demand awarded in the DA market
Settlements, metering & client relations (SMCR)	SMCR	0.9%	50%	50%	Monthly customer charge of $1,000 per business associate ID
Total		100%			
Composite Percentage			**67.1%**	**32.9%**	

Source: CAISO

3.5 Midwest ISO

The Midwest ISO (MISO) has three primary rates for recovery of its costs: Schedule 10 – ISO Cost Recovery Adder; Schedule 16, Financial Transmission Rights (FTR) Administrative Service Cost Recovery Adder; and Schedule 17 - Energy and Operating Reserve Markets Support Administrative Service Cost Recovery Adder. There are some sub-categories to these schedules applicable to specific customers, but only the primary rates are discussed herein.

For all the rates, monthly charges are calculated based on budgeted costs and estimated MWhs of transmission service less the number of MWhs derived from the sub-categories. The charges change on a monthly basis and are trued up in the following month's calculation to reflect actual costs and actual MWhs of Transmission Service.

3.5.1 Schedule 10 - ISO Cost Recovery Adder

The cost recovery mechanism and charges in Part II of Schedule 10 are applicable to all Transmission Customers, Transmission Owners and Appendix I entities whose filings have been approved by the Commission. The costs recovered under this Schedule 10 include the costs associated with building and operating MISO's Security Center, including capital costs and operating expenses; and costs associated with administering the Tariff.

Rate Schedule 10 is a two-part rate, a "Reserved Capacity Rate" and an "Energy Rate". The Reserved Capacity Rate is multiplied by billing units of Reserved Capacity, and the Energy Rate is multiplied by billing units of MWhs of scheduled energy. In the rate calculations, 50% of the billing units used are based on MWhs of Reserved Capacity and 50% of the billing units are based on MWhs of Energy.

While the rate changes monthly and is trued-up to actuals, the range for the combined demand and energy rate in 2010 was from $0.1051/MWh to a high of $0.1691/MWh.

3.5.2 Schedule 16 - Financial Transmission Rights (FTR) Administrative Service Cost Recovery Adder

This FTR Administrative Service Cost Recovery Adder provides for the recovery of all costs incurred by the Transmission Provider, inclusive of all costs resulting from assignment or allocation of costs to the Service. The Transmission Provider's costs incurred in providing the Service include costs associated with:

1. Coordination of FTR bilateral trading;
2. Administration of FTRs through allocation, assignment, auction or any other process accepted by the Commission;
3. Support of the Transmission Provider's on-line, Internet-based FTR tool;
4. "Simultaneous feasibility" analyses to determine the total combination of FTRs and Option B GFA entitlements that can be outstanding and accommodated by the Transmission System at a given point in time; and,
5. Administration of FTRs and revenue distribution.

The billing determinants for the FTR Administrative Service Cost Recovery Adder equal the total amount of FTR volume for all FTR Holders and Option B GFA entitlements, expressed in MW. The total FTR volume equals the MW of FTR capacity in effect in each hour for all FTRs held during the applicable month. While the rate changes monthly and is trued-up to actuals, the range in 2010 was from $0.0109/MWh to a high of $0.0194/MWh.

3.5.3 Schedule 17 - Energy and Operating Reserve Markets Support Administrative Service Cost Recovery Adder

This Energy and Operating Reserve Markets Support Administrative Service Cost Recovery Adder provides for the recovery of all costs incurred by a Transmission Provider, inclusive of all costs resulting from the assignment or allocation of costs to the Service. The Transmission Provider's costs incurred in providing the Service include costs associated with:

1. Market modeling and scheduling functions;
2. Market bidding support;
3. Locational marginal pricing support;
4. Market settlements and billing;
5. Market monitoring functions; and,
6. Simultaneous co-optimization for the scheduling and enabling of the least-cost, security-constrained commitment and dispatch of Generation Resources to serve Load and provide Operating Reserves in the Midwest ISO Balancing Authority Areas while also establishing a spot energy market.

The billing determinants for the Energy and Operating Reserve Markets Support Administrative Service Cost Recovery Adder are:

1. All Actual Energy Injections into the Transmission System by all Market Participants, including deliveries to the Transmission System from generation located both within the Transmission System and outside of the Transmission System,
2. All Actual Energy Withdrawals from the Transmission System by all Market Participants, including MWh delivered to loads located both within the Transmission System and outside of the Transmission System including all out and through transactions using the Transmission System; and,
3. All Bids or Offers for Energy that settle in the Day-Ahead Energy and Operating Reserve Market, but do not actually inject MWh into or extract MWh from the Transmission System in the Real-Time Energy and Operating Reserve Market.

While the rate changes monthly and is trued-up to actuals, the range in 2010 was from $0.0727/MWh to a high of $0.1125/MWh.

3.5.4 Midwest ISO Cost Recovery From Load and Supply

The following table shows the percentage of Midwest ISO's revenue requirement that is recovered from each rate, as well as billing determinants used and the whether the charges are recovered from load, supply, or both.

Table 3-6
Midwest ISO Cost Recovery

Rate	Percent of Revenue Requirement	Load	Supply	Billing Determinants
Schedule 10 - ISO Cost Recovery Adder	45%	100%		50% to MWh of load, 50% based on peak capacity for month
Schedule 16 - FTR Administrative Service Cost Recovery Adder	6%	100%		MW of FTR capacity
Schedule 17 - Energy and Operating Reserve Markets Support Administrative Service Cost Recovery Adder	49%	50%	50%	MWh of gen, load, and virtual
Composite Percentage		**75%**	**25%**	

Source: Midwest ISO 2009 FERC Form 1 and CAISO 2012 Cost of Service Study, p. 38

3.6 ERCOT

ERCOT system administration fees are charged to market participants for use of ERCOT scheduling, settlement, registration and other related system and equipment. ERCOT has numerous other fees to recover cost of security screening, interconnection studies, map sales and copying. Table 1-6 below shows ERCOT fee schedule effective January 1, 2011:

Table 3-7
ERCOT Rates

Description	Calculation/Rate/Comment
ERCOT System Administration fee	$0.4171 per MWh to fund ERCOT activities subject to Public Utility Commission of Texas (PUCT) oversight. This fee is charged to all Qualified Scheduling Entities (QSEs) based on Load represented.
Other Charges	
ERCOT Security Screening Study	A preliminary study of the impacts of a proposed generation plant conducted by ERCOT staff - $1,000 (10MW to 74MW) $2,000 (75MW to 149 MW) $3,000 (150MW to 249MW) $4,000 (250MW to 499MW) $5,000 (500MW and above)
Full Interconnection Study	Costs incurred by the Transmission and/or Distribution Service Provider (TDSP) for completing a detailed study - $15 per MW (Not Refundable – to support ERCOT system studies and coordination)
Map Sale fees	$20 - $40 per map request (by size)
Qualified Scheduling Entity	$500 per Entity

Application fee	
Competitive Retailer Application fee	$500 per Entity
Mismatched Schedule Processing fee	$1 per mismatched event - Assessed to QSEs submitting schedules referencing each other where the schedules do not match
Voluminous Copy fee	$0.15 per page in excess of 50 pages

Ninety eight percent of ERCOT's revenue requirement is recovered from Load with the System Administration Fee. The remaining revenue requirement is recovered with the various charges shown in Table 1-5.

3.7 Southwest Power Pool

Southwest Power Pool (SPP) current tariffs includes following schedules:

3.7.1 Schedule 1 - Scheduling, System Control and Dispatch Services

Scheduling, System Control and Dispatch Service is required to schedule the movement of power through, out of, within or into a Control Area. The SPP Tariff shows both on peak and off peak rates for Schedule 1. Both the hourly on peak and off peak rates are shown as $0.1711/MWh.

Schedule 1 A: TARIFF ADMINISTRATION SERVICE:

The Transmission Provider provides Tariff Administration Service to carry out its responsibilities. The Transmission Customer must purchase this service from the Transmission Provider. It includes:

1. **Administration Charge:**
   An administration charge is applied to all transmission service to cover the SPP's expenses related to administration of the Tariff. For Point- To-Point Transmission Service, this charge can be up to $0.225 per MW per hour for all capacity reserved. For Network Integration Transmission Service this charge can be up to $0.225 per MW per hour for the 12 month average of the Transmission Customer's coincident Zonal Demands used to determine the Demand Charges under Schedule 9 multiplied by the number of all hours of the applicable month. The charge per MW per hour shall be the same for Point-To-Point Transmission Service as for Network Integration Transmission Service.

   For each calendar year, the SPP establishes this administration charge by dividing projected expenses based on its budget for the calendar year divided by the projected annual Schedule 1-A billing units for the calendar year. SPP reconciles actuals to budgeted figures and shall adjust charges for the following calendar year to reflect either over or under recoveries of its costs for the prior year to allow it to recover its actual costs. In projecting and recovering its expenses, SPP recovers 100% of its total expenses through this charge up to the cap of $0.225 per MW per hour for all transmission service.
2. **Transmission Service Request Charges:**
   The Transmission Customer pays SPP a charge for each new Transmission Service Request as follows:
   a. For Firm Point-To-Point Transmission Service:
      Reservations less than one month: $100
      Reservations one month or longer: $200
   b. For Non-Firm Point-To-Point Transmission Service:
      Each Reservation: $0
3. **Bad Debt Expenses:**

> SPP includes in its charges under this Schedule a component to cover estimated bad debts. The Transmission Provider reconciles actual results to estimates and adjusts future monthly charges to reflect either over or under recoveries.

The cost recovery for SPP market participants is 100 percent from Load.

4.0 RATE SCHEDULE 1 STUDY METHODOLOGY

The NYISO RFP for the RS-1 Study included a list of specific deliverables to be included in this report. In addition to the comparison of other ISO/RTOs provided in Section 2 above, the scope of work requested in the RFP and related to the cost analysis, was as follows:

1. An assessment of the NYISO's markets/service categories to determine whether the current basis for allocating the NYISO's costs of these markets/service categories is reasonable, whether there are other more reasonable bases for allocating the NYISO's costs with regard to these markets or service categories, and if there are, to identify them. This assessment should include all NYISO markets and products, recognizing at a minimum the markets currently identified as non-physical contributors. This assessment should also identify the respective groups/classes of NYISO Market Participants which cause or benefit from each specific market/service category utilizing cost-causation principles.

2. Identification of potential billing determinants to be used to allocate NYISO costs for each of the respective markets/service categories. If the assessment of the NYISO's markets/service categories identified alternative bases for allocating the NYISO's costs with regard to these markets or service categories, identify the billing determinants to be used in such allocation. Although the NYISO currently recovers its annual budget costs on megawatt-hours (MWh) of transacted withdrawals and injections and contributions from non-physical contributors, the vast majority of the funds it recovers are from transacted withdrawals and injections. The Consultant's recommendation for billing determinants should provide options that would allow the NYISO to minimize its reliance on transacted withdrawals and injections. Variability in market volumes as a result of the economy and energy efficiency initiatives, among other reasons, can create divergence between forecasted and actual transacted withdrawals and injections, based on cost causation principles.

3. Evaluation of the NYISO's budgets to allocate, if there is a basis, the specific costs appropriate to be recovered from the each of the groups/classes of NYISO Market Participants causing or benefiting from activity in each respective market/service category.

4. Detailed calculations supporting all recommendations on the NYISO's recovery of annual costs – whether the recommendation is to keep the current methodology or to revise it.

5. The report should also provide supporting data for both an unbundled rate design structure by market/service category, with billing determinants set forth AND a bundled rate design, retaining the allocation of the annual budget to transacted withdrawals and injections, but changing (as necessary) the NYISO's current percentage allocations (e.g., 80%/20%). Any recommendation for a bundled rate design shall address contributions from the current non-physical contributors.

6. Evaluation of the NYISO's FERC fees to allocate, if there is a basis, the specific costs appropriate to be recovered from the each of the groups/classes of NYISO Market Participants causing or benefiting from activity in each respective market/service category

4.1 Stakeholder Involvement

To meet these objectives, B&V has followed a systematic process that included a number of steps. Initially, we obtained input from stakeholders through meetings with Market Participant (MP) groups and providing opportunity for stakeholders to provide written comments as well. We met with the following groups to seek input on the questions provided in Appendix A:

- Transmission Owners
- End Use Customers

- Public Power
- Generators
- Other Suppliers

As part of the stakeholder meetings with MPs, B&V requested written responses to a survey (see Appendix A) on the importance of certain rate design principles and their importance to the development of rates for Rate Schedule 1. The MPs were requested to rank the rate design principles on a scale of 1 to 10 with 10 being the most important consideration in developing Rate Schedule 1. We received seven responses with the principles ranked as well as two additional responses with general comments. The ranking of rate design principles from most important to least important is as follows:

1. Cost Causation
2. Transparency
3. Benefits Received
4. Ability to Induce Targeted Market Behavior
5. Materiality
6. Predictability
7. Administrative Ease
8. Simplicity
9. Matching Costs with Revenues
10. Gradualism

4.2 NYISO Management Interviews

In addition to the stakeholder process, we also provided data requests to the NYISO for both historical data and 2011 budget data for our review. Other data reviewed included organization charts, billing and invoicing reports, and project plans. As part of our process of understanding the NYISO data and the existing services provided by the NYISO, we held a series of interviews with NYISO Staff. Interviews were held with the following:

- Mary McGarvey, VP and Chief Financial Officer
- Chris Russell, Manager, Customer Settlements
- Cheryl Hussey, Controller and Assistant Treasurer
- Rick Gonzales, Sr. VP and Chief Operating Officer
- Rana Mukerji, Sr. VP, Market Structures
- Rich Dewey, Sr. VP and Chief Information Officer
- Wayne Bailey, VP, Enterprise Services
- Henry Chao, VP, System & Resource Planning
- Tom Rumsey, VP, External Affairs
- Janet Joyce, Director, Product and Project Management
- Nicole Bouchez, Manager, Market Mitigation and Analysis

As a result of the interview process, we had numerous contacts with other NYISO staff as additional detail and further information was required.

4.3 Development of Service Categories

The primary tool B&V used to develop its list of service categories was the 2011 Budget and the associated cost centers that NYISO uses to categorize its costs. Other considerations were given for the service categories used by other ISO's and to previous Rate Schedule 1 studies. Our preliminary list of service categories is shown in Table 4-1.

Table 4-1
Service Categories

1	Grid Operations
2	Energy Market Operations
3	Capacity Markets
4	Demand Response
5	System and Resource Planning
6	TCC Market Operations
7	Virtual Market Operations
8	Shared Services

These eight service categories were later merged into seven categories when Grid Operations and Energy Market Operations were combined to create a category Grid and Energy Market Operations. Based on our discussions with the NYISO, the combination of these two categories eliminated unnecessary duplication and more closely reflected the way costs were incurred.

4.4 Service Category Definitions

Black & Veatch has identified the following service categories for allocation of the Rate Schedule 1 costs.

1. Grid and Energy Market Operations
   - Conduct and administer the day ahead energy market
   - Conduct and administer the ancillary services markets
   - Manage energy flows and operate the real-time balancing market
   - Commitment analysis and scheduling
   - Allocated portion of Shared Services

2. Capacity Markets
   - All activities necessary to conduct and administer the ICAP market
   - Allocated portion of Shared Services

3. Demand Response
   - All activities necessary to conduct and administer NYISO's demand response programs:

- Day Ahead Demand Response Program (DADRP)
- Emergency Demand Response Program (EDRP)
- ICAP Special Case Resources (SCR) program
- Demand Side Ancillary Services Program (DSASP)

- Allocated portion of Shared Services

4. System and Resource Planning
   - Load forecasting and energy efficiency
   - Transmission and Interconnection Studies (net of any revenue received for studies)
   - System modeling
   - Long term planning
   - Allocated portion of Shared Services

5. TCC Market Operations
   - All activities necessary to conduct and administer the TCC Market
   - Allocated portion of Shared Services

6. Virtual Market Operations
   - All activities necessary to conduct and administer the Virtual Market
   - Allocated portion of Shared Services

7. Shared Services

4.5 Description of Cost Allocation Process

4.5.1 Direct Assigned Costs

Based on the B&V discussions with NYISO Staff and our own independent analysis of the detailed cost center functions, a service category was assigned to each NYISO cost center. For those cost centers that were predominately related to a single service category, the costs were directly assigned to the category. In some cases, there were small amounts of costs in a category that might be incurred to support another cost category function. In that case, B&V attempted to determine if data was available to permit a direct assignment between categories. Where the NYISO staff did not have such data, B&V attempted to determine if there was a consistent pattern of costs related to the two categories over time and if that cost represented a significant portion of the budgeted costs.

Where the split between categories differed from year to year and amounted to a small percent of only one cost center, in the absence of data B&V assigned all of the costs to the primary service category. In our view, the costs assigned to the primary category that might have been costs for another category had in aggregate a minimal impact on the overall allocation process.

4.5.2 Shared Services Cost Allocation

Costs that are classified as Shared Services are allocated to the other service categories using one of two allocation factors. The first allocation factor, “Allocate on Payroll”, is based on the share of Salaries and Benefits that have been direct assigned to the other service categories. The second allocation factor, “Allocate on All”, is based on the share of all costs that have been direct assigned to the other service categories. The allocation percentages used are shown below:

Table 4-2
Shared Services Allocation Factors

Description	Grid and Energy Markets	Capacity Markets	Demand Response	System and Resource Planning	TCC Market Ops	Virtual Market Ops
Allocate on Payroll	64.6%	4.9%	2.4%	22.1%	3.8%	2.1%
Allocate on All	70.2%	4.4%	2.8%	17.2%	3.6%	1.9%

The cost centers that were directly assigned to service categories, plus the cost centers that are allocated to Shared Services, are shown in Tables 4-3 through 4-9. Where cost centers are split between two service categories, the percentage assigned to each service category is shown. The appropriate split between multiple cost centers was based on discussions with and analysis by NYISO staff.

Table 4-3
Cost Centers Directly Assigned to Grid and Energy Market Operations

Market Operations Products (86%)	Power Systems Application Engineering
Grid Operations Products	Commitment Analysis
Grid Operations	Scheduling
System Operator Training	Operations Performance & Analysis
Reliability Compliance & Assessment	Operations Analysis & Services
Power System Operators	Market Design (86%)
Reliability Compliance & Industry Affairs	Market & Employee Training (86%)
Price Validation (86%)	Energy Markets Products (86%)
Operations Engineering	Operations & Reliability Products
Energy Market Operations (86%)	Dept of Energy Project

Table 4-4
Cost Centers Directly Assigned to Capacity Markets

Auxiliary Market Operations (75%)
Auxiliary Market Products (60%)

Table 4-5
Cost Centers Directly Assigned to Demand Response

Auxiliary Market Operations (25%)
Auxiliary Market Products (40%)

Table 4-6 Cost Centers Directly Assigned to System and Resource Planning
System & Resource Planning
Load Forecasting & Energy Efficiency
Transmission Studies
Interconnection Projects
System Modeling
Long Term Planning
Reliability & Economic Planning
Interconnection Studies
Planning & TCC Products (20%)

Table 4-7 Cost Centers Directly Assigned to TCC Market Operations
TCC Market Operations
Planning & TCC Products (80%)

Table 4-8 Cost Centers Directly Assigned to Virtual Market Operations
Market Operations Products (14%)
Price Validation (14%)
Energy Market Operations (14%)
Market Design (14%)
Market & Employee Training (14%)
Energy Markets Products (14%)

Table 4-9 Cost Center Groups Assigned to Shared Services	
Executive	General Counsel
Smart Grid Group	External Affairs
Finance & Accounting	Market Structures (Executive Mgt. only)
Human Resources	Enterprise & Customer Services
Information Technologies (excluding Market Operations Products & Grid Operations Products)	Product & Project Management (Executive Mgt. only)
Operations (Executive Mgt. only)	Research & Development
Facilities and Safety	Strategic & Business Planning
Infrastructure Products	Market Mitigation & Analysis
Finance Products	Internal Auditing
Business Intelligence Products	Corporate

4.6 Assignment of Cost Responsibility

In addition to the cost center categories, we assigned each line item to one of four cost responsibility categories. The four cost responsibility categories were load, generation, both, and other. Where the costs were incurred primarily for load or generation, those costs were directly assigned to load or generation. B&V used either the principle of "cost causation" or the principle of "benefits received" as the primary factor for cost allocation In other cases, based on both cost causation and benefits received, costs were assigned to the "both" category, and these costs are shared on an equal basis between load and generation.

For example, activities and related costs associated with Customer Settlements apply to both load and generation, thus it is necessary to allocate these costs between load and generation. Based on our review of the number of customers in each category, it was reasonable to split these costs equally between the two groups. For our purposes, the cost responsibility category of "both" represented costs that should be split equally between load and generation.

The "other" category reflects costs that could not be directly assigned to either load or generation. This category represented costs that required allocation to determine the share of costs for each of load and generation. The cost category "other" represented costs that were typically overheads that B&V split between load and generation based on the direct assigned costs of the service category it is allocated to. This is consistent with traditional cost allocation methods for allocating corporate overheads such as human resources and finance.

As an example, assume a shared service cost center has $1,000 to allocate between the service categories, and 20% goes to Capacity Market and 10% goes to Demand Response. The cost responsibility of the $200 allocated to Capacity Markets would be split 50%50% between load and supply because that is the how costs are classified for all the direct assigned costs in Capacity Markets. The $100 allocated to Demand Response would be allocated 100% to load based on the classification of direct assigned cost in Demand Response.

This process is repeated for both the costs that are "Allocated on Payroll" and "Allocated on All".

5.0 COST ALLOCATION ANALYSIS

This section summarizes the results of the cost allocation process and unbundling of the NYISO costs recovered with Rate Schedule 1. The basis for cost allocation was the 2011 budget. One pro forma adjustment was made to remove FERC fees ($12 million) from the approved budget. There is a proposed separate recovery mechanism for FERC fees and it is not applicable to RS-1 cost recovery. An alternative cost allocation analysis using a five-year average of NYISO costs is presented in Appendix B. As described in the previous section, for each line item in the 2011 budget, the following procedure was used:

1. Direct assign the cost to a specific service category or, where such a direct assignment is not feasible, to the Shared Service category.
2. Classify the cost responsibility of each item as Load, Supply, Both, Non-Physical or Other.
3. Classify Shared Services as “Allocate on Payroll” or “Allocate on All”.
4. Allocate Shared Services to the service categories using allocation factors based on the directly assigned costs.
5. Calculate the classification of costs to load, supply, or both for all direct assigned costs.
6. For Shared Services costs, calculate the costs classified as Load, Supply, Both, or Non-Physical and then allocate these classified costs to each service category
7. Result is total cost of service to be recovered from each service category and the amounts to be recovered from load and supply.
8. Develop billing determinants for each service category.
9. Divide cost of service for each service category by the appropriate billing determinants to derive unit costs of service. This is the equivalent of what fully cost based rates would be on an unbundled basis.

5.1 Cost Allocation by Service Category

The results of the cost allocation process are shown in Table 5-1. This is the result of completing steps 1 through 4 of the above list. This represents the total cost of service that is reasonable to consider as the cost basis for unbundled rates.

Table 5-1
Summary of Cost Allocation by Service Category
2011 Budget

Description	Grid and Energy Markets	Capacity Markets	Demand Response	System and Resource Planning	TCC Market Ops	Virtual Market Ops	Shared Services	Total Cost of Service
	$000	$000	$000	$000	$000	$000	$000	$000
Direct Costs Assigned	$25,801	$1,610	$1,024	$6,323	$1,321	$682	$97,633	$134,393
% share of total	19.2%	1.2%	0.8%	4.7%	1.0%	0.5%	72.6%	100.0%
Allocation of Shared Services	$66,124	$4,508	$2,574	$18,910	$3,607	$1,911		$97,633
Total Cost of Service	$91,924	$6,118	$3,597	$25,233	$4,928	$2,592	$0	$134,393
	68%	5%	3%	19%	4%	2%		

5.1.1 Scenario Analysis

As shown in Table 5-1, the cost allocation process for Rate Schedule 1 is unique from traditional cost allocation in that 73% of its costs are considered Shared Services that cannot be directly assigned to Service Categories. Allocation of these shared or overhead type costs is somewhat subjective. We found that the decision of whether a shared service was classified as "both", where costs are split 50/50 between load and supply; or "other", where costs are split between load and supply based on the split of the direct assigned costs, resulted in large swings in the overall allocation between load and supply. In the following tables, we present the results for each service category under two scenarios. Scenario 1 classifies the majority of Shared Services costs as "other". Some customer related cost centers remain classified as "both". In Scenario 2, a larger number of the Shared Services costs are classified as "both". The cost center that has the biggest impact based on this change is Information Technology. The total cost in this category alone is over $34 million, which results in a significant difference between Scenario 1 and Scenario 2.

5.1.2 Grid and Energy Market Operations

Table 5-2 shows the costs allocated to load and supply, and the differences between Scenario 1 and Scenario 2 for Grid and Energy Market Operations. The direct assigned costs, using the cost centers identified in Table 4-3, are allocated 83% to load and 17% to supply, and are the same for both scenarios. A detailed explanation of the allocation rationale between load and supply is shown in Appendix C. The differences between the two scenarios are based on the classification of Shared Services, as discussed in the prior paragraph. The midpoint of the two scenarios is 74% / 26%.

Table 5-2
Grid and Energy Markets Operations Cost Assignment

	Scenario 1		Scenario 2	
Description	Costs ($000)	% Share	Costs ($000)	% Share
Direct Assigned Costs				
Load	$21,415	83%	$21,415	83%
Supply	$4,386	17%	$4,386	17%
	$25,801		$25,801	
Total Costs Including Shared Services				
Load	$73,456	80%	$58,483	64%
Supply	$18,468	20%	$33,441	36%
	$91,924		$91,924	

5.1.3 Capacity Markets

Table 5-3 shows the costs allocated to load and supply, and the differences between Scenario 1 and Scenario 2 for Capacity Markets. The direct assigned costs, which comprise 75% of the Auxiliary Market Operations cost center and 60% of the Auxiliary Markets Products cost center, are allocated 50% to load and 50% to supply, and are the same for both scenarios. Both scenarios result in a split of 50% / 50%.

The basis for allocating Capacity Markets 50/50 between load and supply lies is based on the premise that both load and supply participate in and benefit from the administration of the ICAP markets equally. Factors include:

- Both sectors are heavily vested in the ICAP auction process with load's obligation to meet established statewide capacity requirements and supply providing and the service.
- The market rules and ICAP manual are roughly equal in terms of load and supply requirements.
- The functions of the software supporting the ICAP market addresses both load and supply equally.

- The processes of the Auxiliary Market Operations group are split roughly equally.
- The demand curve reset process (occurring every three years) represents an analysis providing certainty and market signals for all market participants.

Finally, a 50/50 split is also consistent with PJM's allocation of its Capacity Resource and Obligation Management Service (Schedule 9-5).

Table 5-3
Capacity Markets Cost Assignment

	Scenario 1		Scenario 2	
Description	Costs ($000)	% Share	Costs ($000)	% Share
Direct Assigned Costs				
Load	$805	50%	$805	50%
Supply	$805	50%	$805	50%
	$1,610		$1,610	
Total Costs Including Shared Services				
Load	$3,070	50%	$3,070	50%
Supply	$3,048	50%	$3,048	50%
	$6,118		$6,118	

5.1.4 Demand Response

Table 5-4 shows the costs allocated to load and supply, and the differences between Scenario 1 and Scenario 2 for Demand Response. The direct assigned costs, which are 25% of the Auxiliary Market Operations cost center and 40% of the Auxiliary Markets Products cost center, are allocated 100% to load, and are the same for both scenarios. The differences between the two scenarios are based on the classification of Shared Services. The midpoint of the two scenarios is 85% / 15%. Demand Response is allocated 100% to Load because Demand Response exists to benefit the end user by reducing the need for additional generation and maintaining a lower marginal cost of energy. Since the Demand Response occurs behind the meter for load it is also appropriately assigned to load.

Table 5-4
Demand Response Cost Assignment

	Scenario 1		Scenario 2	
Description	Costs ($000)	% Share	Costs ($000)	% Share
Direct Assigned Costs				
Load	$1,024	100%	$1,024	100%
Supply	$0	0%	$0	0%
	$1,024		$1,024	
Total Costs Including Shared Services				
Load	$3,430	95%	$2,541	71%
Supply	$168	5%	$1,056	29%
	$3,597		$3,597	

5.1.5 System and Resource Planning

Table 5-5 shows the costs allocated to load and supply, and the differences between Scenario 1 and Scenario 2 for System and Resource Planning. The direct assigned costs, using the cost centers identified in Table 4-6, are allocated 88% to load and 12% to supply, and are the same for both scenarios. A detailed explanation of the allocation rationale between load and supply is shown in Appendix C. The differences between the two scenarios are based on the classification of Shared Services. The midpoint of the two scenarios is 76% / 24%.

Table 5-5
System and Resource Planning Cost Assignment

	Scenario 1		Scenario 2	
Description	Costs ($000)	% Share	Costs ($000)	% Share
Direct Assigned Costs				
Load	$5,537	88%	$5,537	88%
Supply	$786	12%	$786	12%
	$6,323		$6,323	
Total Costs Including Shared Services				
Load	$21,042	83%	$16,386	65%
Supply	$4,191	17%	$8,847	35%
	$25,233		$25,233	

5.1.6 TCC Market Operations

Table 5-6 shows the costs allocated to TCC Market Operations. The TCC market is a non-physical market with separate and discrete participants and is not related to either load or supply. The direct assigned costs are the TCC Market Operations cost center and 80% of the Planning and TCC Products cost center. There is no difference between Scenario 1 and Scenario 2 as all costs are assigned to non-physical. Consistent with current NYISO practice it is assumed that these costs would be recovered directly from the participants in the TCC market.

Table 5-6
TCC Market Operations Cost Assignment

	Scenario 1		Scenario 2	
Description	Costs ($000)	% Share	Costs ($000)	% Share
Direct Assigned Costs				
Non-Physical	$1,321	100%	$1,321	100%
Total Costs Including Shared Services				
Non-Physical	$4,928	100%	$4,928	100%

5.1.7 Virtual Market Operations

Table 5-7 shows the costs allocated to Virtual Market Operations. The Virtual market is a non-physical market and is not related to either load or supply. The direct assigned costs are a 14% share of the following Grid and Energy Markets cost centers:

- Market Operations Products

- Price Validation
- Energy Market Operations
- Market Design
- Market & Employee Training
- Energy Markets Products

The basis for the 14% allocation is from a study of share of day ahead virtual transactions as a percentage of the entire energy market, on both a MWh and dollar basis. On a MWh basis, day ahead virtual trading was 14.77% of the total energy market. On a dollars transacted basis, the virtual share was 13.52%. 14% represents a reasonable average of these values. There is no difference between Scenario 1 and Scenario 2 as all costs are assigned to non-physical. Consistent with current NYISO practice it is assumed that these costs would be recovered directly from the participants in the Virtual market.

Table 5-7
Virtual Market Operations Cost Assignment

	Scenario 1		Scenario 2	
Description	Costs ($000)	% Share	Costs ($000)	% Share
Direct Assigned Costs				
Non-Physical	$682	100%	$682	100%
Total Costs Including Shared Services				
Non-Physical	$2,592	100%	$2,592	100%

5.1.8 Summary of Total Cost of Service

Table 5-8 summarizes the combination of all service categories into one composite allocation between load, supply, and non-physicals. We believe that the results of the two scenarios provide the upper and lower bounds for the split between load and supply. The result of this allocation process in Scenario 1 is a split between load, supply, and non-physicals of 75% / 19% / 6%. This is an 80% / 20% split for physical markets. The result of Scenario 2 shows the allocation is 60% / 34% / 6% (63% / 37% split for physical markets). The midpoint of these two scenarios is 67% / 27% / 6%, which is an effective split between load and supply of 72% / 28% when excluding non-physicals.

We conclude that the two cost studies present a range of values that could be considered a reasonable split between load and supply. We find that the upper and lower bounds of the studies represent the limits of what would be reasonable, and therefore recommend a split near the midpoint as a reasonable settling point. Given the nature of cost analysis and our view that no single cost analysis should be the basis for rates because of the inherent arbitrary nature of the allocation of joint and common costs, we believe that the resulting range of cost allocations contained in our report properly reflect costs and benefits for various services and for the allocation between load and supply.

Table 5-8
Summary of Total Cost of Service

Description	Scenario 1		Scenario 2	
	Costs ($000)	% Share	Costs ($000)	% Share
Direct Assigned Costs				
Load	$28,781	78%	$28,781	78%
Supply	$5,976	16%	$5,976	16%
Non-Physical	$2,003	5%	$2,003	5%
	$36,760		$36,760	
Total Costs Including Shared Services				
Load	$100,998	75%	$80,480	60%
Supply	$25,875	19%	$46,392	34%
Non-Physical	$7,520	6%	$7,520	6%
	$134,393		$134,393	
Average of Both Scenarios				
Load	67%			
Supply	27%			
Non-Physical	6%			

To this point in the report, the analysis has been based on the 2011 budget. The 2011 budget provided a more granular level of detail to get a better understanding of costs. An alternate version of the cost allocation process has also been completed using a five-year average of costs from 2007 to 2011. The results of this analysis are presented in Appendix B. As further discussed in Appendix B, the results using a five-year average revenue requirement are nearly identical to using only the 2011 budget. Using the five-year average, the average of the two scenarios is 66% / 27% / 7%. The load/supply split for physical markets it 71% / 29%.

5.2 Billing Determinants

In addition to the cost of service study, B&V collected data related to billing determinants available from the NYISO. We have reviewed these billing determinants as well as those used by other RTO/ISOs. We have discussed potential billing determinants with the BPWG and sought input from related to specific billing determinants. We have reviewed and tested specific billing determinants for different Service Categories. Based on this review, B&V believes that megawatt-hours (MWh) remain the primary billing determinant for use by NYISO.

The billing determinants recommended for each service category are:

Grid and Energy Market Operations
Load: MWh of actual withdrawals including bilateral transactions
Supply: MWh of actual injections including bilateral transactions

Capacity Markets
Annual sum of monthly ICAP requirements (MW-month)

Demand Response
Load: MWh of actual withdrawals including bilateral transactions
Supply: MWh of actual injections including bilateral transactions

System and Resource Planning
Load: MWh of actual withdrawals including bilateral transactions
Supply: MWh of actual injections including bilateral transactions

TCC Market Operations
MWh of Transmission Congestion Contracts transacted

Virtual Market Operations
MWh of Virtuals transacted

5.3 Unit Costs of Service

Once all costs have been allocated to the appropriate service category, the next step is to develop unbundled unit costs and rates. The costs for each service category are divided by the billing determinants identified for each category to produce a unit rate for each service. Should a decision be made to move from a bundled rate to fully unbundled rates, the following are the rates that would be charged. With fully unbundled rates, the revenue from TCC and Virtual markets would no longer be credited back to other MPs, but would be a stand alone rate for the recovery of the RS-1 revenue requirement. The unbundled unit rates for each service category are shown in Tables 5-9 through 5-11. Tables 5-9 and 5-10 present the unbundled rates using Scenarios 1 and 2, respectively. Table 5-11 is the midpoint of the two scenarios and would be our recommendation for future use if unbundled rates were to be implemented. The billing determinant basis presented is based on 2010 actual billing determinants. An alternate version using a four-year average of billing units from 2007 through 2010 is presented in Appendix B.

The unit rates for Grid and Energy Market Operations, Demand Response, and System and Resource Planning all have a separate load and supply rate. The load rate for each is multiplied by the withdrawal MWh to get revenue from Load customers. The supply rates are multiplied by the injection MWh to get supply revenue. The total cost of service for Capacity Markets is recovered from LSEs making transactions in the ICAP market. If the unbundled rates were applied, there would be no load/supply component. Similarly, for both the TCC and Virtual markets, the unit rate is applied to the MWh transacted in each market, with no load/supply differentiation.

Table 5-9
Unbundled Unit Rates – Scenario 1

Description	Grid and Energy Markets	Capacity Markets	Demand Response	System and Resource Planning	TCC Market Ops	Virtual Market Ops
Total Cost of Service						
Load ($000)	$73,456	$3,070	$3,430	$21,042		
Supply ($000)	$18,468	$3,048	$168	$4,191		
Non-Physical ($000)					$4,928	$2,592
	$91,924	$6,118	$3,597	$25,233	$4,928	$2,592
Billing Units						
Withdrawals (MWh)	167,727,655		167,727,655	167,727,655		
Injections (MWh)	172,974,970		172,974,970	172,974,970		
ICAP (MW-month)		425,078				
TCC (MWh)					132,453,965	
Virtual (MWh)						29,755,966
Unit Rates						
Load ($/MWh)	$0.4379		$0.0204	$0.1255		
Supply ($/MWh)	$0.1068		$0.0010	$0.0242		
ICAP Load ($/MW-month)		$7.22				
ICAP Supply ($/MW-month)		$7.17				
TCC ($/MWh)					$0.0372	
Virtual ($/MWh)						$0.0871

Table 5-10
Unbundled Unit Rates – Scenario 2

Description	Grid and Energy Markets	Capacity Markets	Demand Response	System and Resource Planning	TCC Market Ops	Virtual Market Ops
Total Cost of Service						
Load ($000)	$58,483	$3,070	$2,541	$16,386		
Supply ($000)	$33,441	$3,048	$1,056	$8,847		
Non-Physical ($000)					$4,928	$2,592
	$91,924	$6,118	$3,597	$25,233	$4,928	$2,592
Billing Units						
Withdrawals (MWh)	167,727,655		167,727,655	167,727,655		
Injections (MWh)	172,974,970		172,974,970	172,974,970		
ICAP (MW-month)		425,078				
TCC (MWh)					132,453,965	
Virtual (MWh)						29,755,966
Unit Rates						
Load ($/MWh)	$0.3487		$0.0152	$0.0977		
Supply ($/MWh)	$0.1933		$0.0061	$0.0511		
ICAP Load ($/MW-month)		$7.22				
ICAP Supply ($/MW-month)		$7.17				
TCC ($/MWh)					$0.0372	
Virtual ($/MWh)						$0.0871

Table 5-11
Unbundled Unit Rates – Midpoint of Both Scenarios

Description	Grid and Energy Markets	Capacity Markets	Demand Response	System and Resource Planning	TCC Market Ops	Virtual Market Ops
Total Cost of Service						
Load ($000)	$65,970	$3,070	$2,986	$18,714		
Supply ($000)	$25,955	$3,048	$612	$6,519		
Non-Physical ($000)					$4,928	$2,592
	$91,924	$6,118	$3,597	$25,233	$4,928	$2,592
Billing Units						
Withdrawals (MWh)	167,727,655		167,727,655	167,727,655		
Injections (MWh)	172,974,970		172,974,970	172,974,970		
ICAP (MW-month)		425,078				
TCC (MWh)					132,453,965	
Virtual (MWh)						29,755,966
Unit Rates						
Load ($/MWh)	$0.3933		$0.0178	$0.1116		
Supply ($/MWh)	$0.1500		$0.0035	$0.0377		
ICAP Load ($/MW-month)		$7.22				
ICAP Supply ($/MW-month)		$7.17				
TCC ($/MWh)					$0.0372	
Virtual ($/MWh)						$0.0871

6.0 ALLOCATION OF FERC FEES

Based on the results of the cost allocation for NYISO's Rate Schedule 1 costs, FERC expenses should be allocated in the same ratio of load, supply, and non-physical as recommended for Rate Schedule 1. B&V reaches this conclusion based on the fact that FERC expenses represent a corporate overhead expense that would otherwise have been shared as an allocation on total direct assigned expenses under the cost methodology employed in the NYISO cost allocation study process. This would have resulted in the approximate 67% / 27% / 6% split that resulted for all other costs (using the midpoint of both scenarios as an example). To develop a different split from the overall cost split would require a different rationale for cost allocation. In the case of regulatory expenses, the most common allocation factors include revenue, operating expenses less fuel and purchased power expense and rate base. Choosing either of the first two options would essentially produce the approximate 67% / 27% / 6% split. Since the NYISO has no rate base in the traditional sense, the third option is not available.

Allocating FERC expenses in some other manner would be inconsistent with typical cost analysis. Therefore, we believe that the most reasonable allocation is the split between load, supply, and non-physicals finally adopted for RS-1.

Additional material will be provided by NYISO staff on the mechanics of FERC fee cost recovery.

7.0 SUMMARY AND CONCLUSIONS

Based on the detailed analysis of costs using principles of cost causation as well as an analysis of the benefits of the NYISO Rate Schedule 1 Costs, it is our view the recovery of RS-1 costs from load and supply should be in the range of the two cost studies performed. As we presented in this report, we find a range of appropriate results between 75% / 19% / 6% and 60% / 34% / 6%. The range is between 80% / 20% and 63% / 37% for the physical markets. We conclude that the two cost studies present a range of values that could be considered a reasonable split between load and supply. Ultimately, if bundled rates are to be continued, we recommend a change from the current 80/20 split to a split that is at or around the midpoint of 72/28. We find that the upper and lower bounds of the studies represent the limits of what would be reasonable, and therefore recommend a split near the midpoint as a reasonable settling point.

Black and Veatch also recommends that the RS-1 rate continue to be billed on a bundled basis using the same procedure that is currently in place, but with a new split between load and supply. The current procedure rebates all revenue collected from non-physical markets to physical injections and withdrawals on a monthly basis[1]. The ratio of the rebate between load and supply should be the ratio that results from this study. We recommend that a true up provision be added to the rate that assures timely recovery of the actual budget dollars approved for each year including any approved adjustments to the budget resulting from extraordinary circumstances.

With respect to cost causation, it is important to consider the nature of the NYISO costs. The costs for the NYISO are characterized by the existence of common costs[2]. NYISO costs may be fixed or variable costs[3] but are typically fixed. The development of this cost allocation is a necessary, although a controversial component for setting rates (bundled or unbundled) for recovery of NYISO Rate Schedule 1 costs. The process is controversial because costs are ultimately reflected in rates and the allocation of a single pot of costs among different customer groups can, of course, cause some customers to experience greater rate changes than other customers.

The key to a reasonable cost allocation is an understanding of cost causation. The total cost of service or revenue requirement is determined for a test period that may be either a historic period or a future period. In our analysis we have used the 2011 budget year as the test period. In addition, we have averaged data over a five year period that includes four years of historical data and the 2011 budget year to test our conclusions based on 2011 alone. The five-year data average illustrates the variability in costs over time and points to factors other than MWs and MWhs that drive costs. For example, Table 7-1 below provides a statistical description of the costs in a selected set of categories.

[1] Per the current Rate Schedule 1, the recovery rate for Non-Physical Resources (TCC and Virtual Trading) is re-set annually, by July 15th for the upcoming January. This permits those Market Participants who are engaged in those markets to know what the charges will be prior to the Fall Auction season/ Winter Capability period (when 6 Month and 1 Year TCCs are auctioned). Any changes to the recovery mechanism for these markets resulting from this study should contemplate a waiver filing for the upcoming reset period (July 15, 2011).

[2] Common costs occur when the fixed costs of providing service to one or more classes or the cost of providing multiple products to the same class use the same facilities and the use by one class precludes the use by another class. In the case of many of the NYISO costs, the use of the fixed costs by one or more customers does not preclude the use of these services by others. This characteristic is significantly different from traditional utility service and will be discussed later.

[3] Fixed costs do not change with the level of service while variable costs change directly with the level of the services provided. Most NYISO costs are fixed and do not vary with changes in MWHs, MWs or customers.

Table 7-1
Sample Statistics for Selected NYISO Cost Categories

Cost Center Group	Mean	Max	Min	Std Dev	Std Dev/Mean	Max Cost Year
Customer Settlements	$1,190,545	$1,336,404	$1,076,784	$111,691	9.38%	2008
Information Technology	$29,666,532	$33,507,385	$25,556,719	$3,077,021	10.37%	2010
Grid Operations	$2,719,448	$2,935,764	$2,534,587	$180,657	6.64%	2008
Forecasting & Planning	$1,649,387	$1,980,054	$1,261,459	$267,983	16.25%	2008
Power System Operations	$5,179,325	$5,836,794	$4,660,044	$445,982	8.61%	2011
Market Programs	$4,840,346	$5,571,659	$3,990,568	$667,037	13.78%	2010
Energy Market Products	$2,710,844	$3,755,909	$1,942,100	$733,388	27.05%	2007

As Table 7-1 illustrates there is minimal variation in some cost centers over this time frame while other cost centers have changed dramatically in the level of the largest cost components of the cost category. Based on discussions with NYISO Staff, it becomes apparent that the pattern of costs in a number of cost categories changes over time. These changes result from external influences such as the emphasis from market participants, orders from the FERC, and changing market dynamics such as growth in a market segment. All of these changes occur within the mission of the NYISO as described in its FERC Form 1 filing:

> NYISO's mission, in collaboration with its stakeholders, is to serve the public interest by maintaining and enhancing the reliable, safe, and efficient operation of the New York State transmission system and promoting and operating a fair and competitive wholesale market for electricity in New York State while providing quality customer service. NYISO facilitates fair and open competition in the wholesale power market and creates an electricity commodity market in which power is purchased and sold on the basis of competitive bidding. NYISO utilizes a bid process for electricity and transmission usage, which enables New York State's utilities and other market participants to offer electricity at competitive prices, rather than regulated rates.

As compared to traditional cost of service studies for electric utilities, the NYISO has a more significant share of common and joint costs that must be allocated among both load and supply and ultimately among unbundled service offerings. Simply, the costs that are easily assigned to a service or to load or supply represent about 28% of the total NYISO revenue requirement. The remainder of the costs represents shared services. For example, the costs of Information Technology[4] have the highest cost of any shared service. These facilities are used to provide services for other service categories and for load and supply. From an economic perspective, any allocation of these costs is arbitrary. Immediately, that means that there is no one allocation of costs between load and supply or between unbundled services that should be given more weight in the determination of cost shares than another method. For that reason, we concluded that there should be more than one cost study developed for NYISO. The differences between cost studies results from how shared services costs are allocated between load and supply. We have attempted to provide an upper and lower bound for the allocation of shared services by using a simple 50%/50% split of these costs as the lower bound and an allocation based on the components of service that were able to be directly assigned to load or supply. By allocating shared services on the direct assignment dollars, an upper bound for cost allocation between load and supply was determined. We further recognize that the classification of costs between load

[4] Includes the cost centers of Networks and Service Desks, Servers and Storage, Network Operations Center Services, and Software Development

and supply also has an impact on the allocation of shared services that creates further variability in the ultimate split of these services between load and supply.

With respect to cost causation and the potential billing determinants, we likewise conclude that billing these costs on MWhs remains the most appropriate rate design so long as the Schedule RS-1 is modified with a provision that permits revenues to match the approved level of budgeted expenses for the year. B&V also analyzed a number of cost categories to determine the relationship between the costs and potential MWh billing determinants. Since both load and supply MWhs are nearly perfectly correlated over the period from 2007-2010 the analysis focused on the use of Withdrawal MWhs as the load metric. (This conclusion is not surprising since conceptually the differences between withdrawals and injections should equal the expected level of losses. In fact, the difference was between 3.1 and 3.8 percent.) The results of our analysis indicate that MWhs have little value in explaining the changes in specific cost categories over the four year period and little value in explaining the total NYISO Rate Schedule 1 costs. Thus, while MWhs is a reasonable basis for a billing determinant to recover the costs MWhs provide little guidance in the allocation of costs.

With respect to total RS-1 costs, there is poor correlation between annual costs and annual MWh load or withdrawals at negative 0.185. Since correlation is a necessary but not sufficient condition for cost causation, it is reasonable to conclude, as one would expect for a largely fixed set of costs, that MWhs do not cause the total NYISO RS-1 costs. Further, testing for causation using regression analysis for individual cost categories produces some counter-intuitive results such as the fact that load MWhs explain over 80% of the variation in a group of corporate costs (Cost Centers: Corporate Credit, Human Resources, Information Technologies and Infrastructure Services). Yet when costs would be expected to explain a high percentage of a cost category such as Commitment and Scheduling load explained less than one percent of the variation. In fact, for many of the cost categories tested, load MWhs (and by extension supply MWhs) explained very limited amounts of variation in NYISO cost categories. Table 4-2 below provides the R-square and the F-statistic for each cost category tested.

Table 7-2
MWhs Load and Cost Regression Statistics

Cost Category	R-Square	F-Test
Executive	0.1%	0.003
Finance	0.3%	0.005
Settlement	60.0%	3.000
Corporate	81.0%	8.600
Information Technology	38.0%	1.200
Market Operations	4.0%	0.080
Grid Operations	11.0%	0.250
Forecasting and Planning	3.0%	0.060
Auxiliary Markets	6.0%	0.120
Commitment and Scheduling	0.0%	0.000
Market Monitoring	57.0%	2.700

The table shows that even with MWh load explaining a significant amount of cost variation, the F-statistic values are also low indicating that the results do not permit rejection of the hypothesis that the model is statistically different from zero.

This analysis suggests that following accepted cost of service principles produces results that rely heavily on the separation of load and supply in the classification phase and less on the allocation phase. As a result, we have reviewed cost centers at a detailed level to assure reasonable classification of costs. We also asked that NYISO Staff closely review the results of our classifications to assure that the results were reasonable based on their experience.

Based on all our analysis, we conclude bundled rates are appropriate for continued use and we recommend a change from the existing 80% / 20% split to a split that is at or near the midpoint of the two studies of 72% / 28%.

APPENDIX A – MARKET PARTICIPANT SURVEY AND QUESTIONS

New York Independent System Operator
Stakeholder Involvement
Market Participant Sector Interviews

1. As a customer of NYISO, what do you think are the pros and cons of the present RS-1 rate?

2. What do you believe represents the best possible options for recovering the costs for NYISO operations? (e.g., rates for individual services, new rate concepts such as fixed charges for certain activities, user-based fees, etc.)

3. What changes, if any, would you like to see made to the RS-1?

4. If you are familiar with the equivalent of the NYISO RS-1 tariff at other ISO/RTOs, which of those designs do you feel would be closest to the kind of tariff you would like the NYISO to implement. Why?

5. Which features of the tariff that you chose in answer to Question 4 above would need to be modified to make that tariff more applicable to the NYISO's particular needs and circumstances?

6. Is there anything in the stakeholder process associated with the current RS-1 review project that you would like to change? Why?

7. If you were involved in the last RS-1 project performed by R. J. Rudden Associates in 2003-2004, how do you feel the current RS-1 review process and/or analysis could be improved, if at all, relative to the 2003-2004 process?

8. Please rate, on a scale of 1-10, with 10 being the most important, the importance of each of the following rate design principles as it applies to RS-1:
   - Cost causation (i.e. who/what kind of activities cause(s) costs to be incurred.)
   - Benefits received (i.e., who receives the benefit of the service, whether or not they cause costs to be incurred.)
   - Administrative ease (i.e., tariff design does not require inordinate time and resource to administer) for the ISO or for customers
   - Transparency (i.e., costs and billing determinants are easily understood, visible and confirmable; tariff wording is clear and unambiguous.)
   - Materiality (i.e. create classes of service only when there is a material number of customers and/or revenue to justify separate classes.)
   - Simplicity (i.e. use as few rate schedules and as much "plain language" as is consistent with meeting the other rate design principles.)
   - Ability to induce targeted market behavior (Example: Should parties requesting the ISO to perform studies not required by their normal scope of work be required to pay for such studies?

- Predictability (i.e., customers can estimate future billings based on their expected activity and NYISO can reasonably anticipate future revenue levels.)
- Matching of costs and revenues (minimizing the difference between the costs included in rates and the costs recovered through rates to limit deferred costs or refunds)
- Gradualism (avoiding abrupt changes in rate levels and/or structure; minimizing adverse customer impacts; this also enhances the objective of predictability.)

9. Are there any new classes of service that you feel ought to be part of NYISO's RS-1 tariff? (Please specify.)

If there are questions that are not covered in enough detail, or if there are time constraints, please provide written responses for any of the above questions that you would like to provide further input.

Please provide any written response to NYISO by January 20, 2011.

APPENDIX B – COST ALLOCATION RESULTS USING A FIVE YEAR AVERAGE TEST PERIOD

The cost of service analysis in the body of the report is based on allocation of the 2011 budget and the actual billing determinants from 2010. As discussed previously, the actual costs in each cost center can vary greatly from year to year. To account for this, B&V prepared an alternative cost of service using the same methodology, but using a five-year average for the test year cost of service. The data used was the year end actuals from 2007 through 2010 and the 2011 budget. We aggregated the granular, line item data that was used for the 2011 budget analysis into the budget category descriptions used by NYISO for each cost center. Examples of budget category descriptions are Salaries and Benefits, Consultants, Building Services, and Capital.

Once the five-year average cost of service was developed, pro forma adjustments were made to adjust for non-recurring one-time costs, or cost centers that no longer exist. The cost allocation procedure was the same, in that each budget category in a cost center was assigned to a service category and classified as load, supply, both, or other. Shared services were allocated to the other service categories using the same methodology as well.

The results of the cost allocation using a 5-year average test period are shown below in Table B-1.

Table B-1
Summary of Cost Allocation by Service Category
Five-Year Average Test Year (2007 – 2011)

Description	Grid and Energy Markets	Capacity Markets	Demand Response	System and Resource Planning	TCC Market Ops	Virtual Market Ops	Shared Services	Total Cost of Service
	$000	$000	$000	$000	$000	$000	$000	$000
Direct Costs Assigned	$23,414	$1,668	$878	$5,464	$1,858	$773	$99,415	$133,470
% share of total	17.5%	1.2%	0.7%	4.1%	1.4%	0.6%	74.5%	100.0%
Allocation of Shared Services	$67,083	$4,760	$2,408	$18,084	$4,868	$2,212		$99,415
Total Cost of Service	$90,497	$6,428	$3,286	$23,548	$6,727	$2,985	$0	$133,470

The analysis was performed for the same two scenarios as done in the 2011 budget version. Scenario 1 has more shared service costs allocated using the load/supply split of the direct assigned costs of the service category it is allocated to and Scenario 2 allocates more shared service costs on a 50/50 split to load and supply. The description and explanation of the scenario analysis is in Appendix C. The results of both scenarios are shown in Table B-2. Scenario 1 results in a 74% / 19% / 7% split between load, supply, and physical markets (compared to 75% / 19% / 6% when only using the 2011 budget). Scenario 2 results in a 59% / 34% / 7% split between load and supply (compared to 60% / 34% / 6% when only using the 2011 budget). The mid point between the two scenarios is 66% / 27% / 7%, which is nearly the same as the 2011 budget version.

Table B-2
Summary of Total Cost of Service
Five-Year Average Test Year (2007 – 2011)

Description	Scenario 1		Scenario 2	
	Costs ($000)	% Share	Costs ($000)	% Share
Direct Assigned Costs				
Load	$26,063	77%	$26,063	77%
Supply	$5,360	16%	$5,360	16%
Non-Physical	$2,631	8%	$2,631	8%
	$34,055		$34,055	
Total Costs Including Shared Services				
Load	$98,217	74%	$78,636	59%
Supply	$25,541	19%	$45,122	34%
Non-Physical	$9,712	7%	$9,712	7%
	$133,470		$133,470	
Average of Both Scenarios				
Load	66.3%			
Supply	26.5%			
Non-Physical	7.3%			

The unit cost analysis was performed in the same manner as discussed in Section 5.3. The difference is the billing units used in Table B-3 are the average billing determinants from 2007 through 2010.

Table B-3
Unbundled Unit Rates
Five-Year Average Test Year and Four-Year Average Billing Determinants
Midpoint of Both Scenarios

Description	Grid and Energy Markets	Capacity Markets	Demand Response	System and Resource Planning	TCC Market Ops	Virtual Market Ops
Total Cost of Service						
Load ($000)	$65,754	$3,222	$2,722	$16,729		
Supply ($000)	$24,743	$3,205	$564	$6,819		
Non-Physical ($000)					$6,727	$2,985
	$90,497	$6,428	$3,286	$23,548	$6,727	$2,985
Billing Units						
Withdrawls (MWh)	171,685,045		171,685,045	171,685,045		
Injections (MWh)	177,621,184		177,621,184	177,621,184		
ICAP (MW-month)		432,523				
TCC (MWh)					202,052,427	
Virtual (MWh)						31,818,425
Unit Rates						
Load ($/MWh)	$0.3830		$0.0159	$0.0974		
Supply ($/MWh)	$0.1393		$0.0032	$0.0384		
ICAP Load ($/MW-month)		$7.45				
ICAP Supply ($/MW-month)		$7.41				
TCC ($/MWh)					$0.0333	
Virtual ($/MWh)						$0.0938

APPENDIX C – COST ALLOCATION RATIONALE

The following provide a more detailed explanation of each cost center and of the allocation of costs between load and supply for cost centers in Grid and Energy Markets, System and Resource Planning, and Shared Services.

Grid and Energy Market Operations

Grid Operations

Direct and coordinate reliable, compliant and economic operations, through Shift Supervisors (SS), of the New York State bulk electrical system maintaining reliability and adherence to applicable tariffs and scheduling protocols. Also supervise Electronics and Communications function of power system operations. Direct and manage shift supervisors who oversee the operation of the bulk power system in compliance with applicable portions of NYISO, NERC, NPCC and NYSRC criteria, standards, policies and tariffs to assure compliance by shift operators.

This cost center is allocated 100% to load based on the management of the grid to satisfy load requirements reliably and safely for end-use customers.

Grid Operations Products

Manage research and development of Grid Operations Products software products and applications.

This cost center is allocated 100% to load based on the costs and the benefits of operating the grid ultimately accrue to load.

Market Operations Products

Manage research and development of Market Operations Products software products and applications for end-user management and analysis of NYISO energy market data (e.g., bids, offers, trades).

This cost center is allocated 100% to load based on the concept that market operations are related to load and the products and analysis is related to energy which is load. Allocating Market Operations activities 100% to load is consistent with PJM's Schedule 9-1, which recovers costs for administering all point to point transmission service 100% from load.

System Operator Training

Responsible for developing, implementing and evaluating a coordinated training program for NYISO and Transmission Owner system operators, to assure reliable interconnected system operation, in compliance with NERC, NPCC and NYSRC training requirements.

This cost center is allocated 100% to load based on this function assuring that the integrated power system is operated efficiently to serve load.

Reliability Compliance and Assessment

Supervise and direct compliance monitoring and reporting of reliability and business standards. This will also include monitoring or proposing the introduction of new reliability and business standards. Manage the NYISO enterprise wide NERC, NPCC, NYSRC, and NAESB compliance and assessment programs. Drive the NYISO's reliability compliance programs to ensure compliance with the North American Electric Reliability Council (NERC) mandatory and enforceable reliability standards. Lead NYISO's development of policies, procedures and controls to meet the NAESB business practice standards.

This cost center is allocated 100% to load based on the benefits of reliability are ultimately load customers. Reliability related costs are consistently recovered 100% from Load at other ISO's. Examples are PJM's Schedule 9-1, ISO-NE's Schedule 3, and California ISO's Core Reliability Services rate.

Power System Operators

Supervise and direct reliable, compliant and economic operations, with the Shift Supervisors, and Power System Operators of the New York State bulk electrical system maintaining reliability and adherence to applicable tariffs and scheduling protocols. Work with Shift Supervisors who direct the operation of the bulk power system in accordance with NYISO, NERC, NPCC and NYSRC criteria and policies.

This cost center is allocated 100% to load based on the purpose of operating a grid to provide reliable cost effective and least cost power to customers within the constraints of the system.

Reliability Compliance & Industry Affairs

Responsible for ensuring the sufficiency of all ISO policies, procedures, and documentation for meeting Operations Departments' reliability compliance with all applicable NERC, NPCC, and NYSRC Reliability standards and rules. Represent the NYISO as primary liaison to various industry organizations and committees that have reliability and business impact on the NYISO, including the ISO Coordinating Committee, NAESB and the ISO/TO/Nuclear Committee. Act as Operations liaison for other Operations Department Management with neighboring control areas (PJM, IESO, HQTE, ISO-NE) responsible for negotiating and maintaining Joint Operating Agreements, special operating protocols, and for negotiating resolution of operating issues that may arise. Support ISO Operating Committee activities as required.

This cost center is allocated 100% to load based on based on the allocation of other system operating costs and how other ISO's allocate reliability costs.

Price Validation

Coordinate daily operation of the Price Validation functions to ensure the correctness of prices from the Energy Market used in Settlements and posted to OASIS.

This cost center is allocated 50%/50% between load and supply based on transparency and benefits accrue to both load and supply equally in confirming prices for both sides of a transaction.

Operations Engineering

Direct and coordinate daily functions of the Operations Engineering department including coordinating and performing systems studies to determine ISO Power System transfer limits, as well as all other aspects of technical engineering support for ISO Operations requirements. The technical engineering studies and engineering support delivered by Operations Engineering are performed in order to achieve the safe and reliable operations of the NYISO in compliance with established external reliability organization compliance requirements (NERC/NPCC/NYSRC). These studies support the short-term planning and operations for the seasonal and year-ahead forecast system conditions. Evaluate the need and effectiveness of computer simulation programs and/or other tools to ensure the safe and reliable operations of the NYISO transmission and generation resources. Direct staff in the review of NYISO controlled and secured facilities, standards and practices for installation, maintenance and testing of bulk power protective relay systems.

This cost center is allocated 100% to load based on the provision of services related to reliability of operations, assessing system requirements in the short term to ensure that appropriate technical parameters are included in system operations.

Energy Market Operations
Direct and coordinate daily functions of the Energy Market Operations department, to include Scheduling and Commitment Analysis as well as Power systems Application Engineering to assure market reliability and accuracy as detailed in the NYISO's Tariffs. Provide leadership to staff responsible for operating the ISO forward Day-Ahead Electricity market and the scheduling of power system facility maintenance outages. Responsible for Subject Matter Expertise support of ISO Energy Markets for the Day-Ahead and the Real-Time load forecasting function and SCUC and RTS design and operation. Responsible for all aspects of the power system network models and ICCP telemetry required to support the ISO Energy Management Systems (EMS) and Business Management Systems (SCUC/RTS), including the state estimator function. Responsible for the validation process of the Energy Markets prices in order to facilitate the NYISO Tariff requirements.

This cost center is allocated 50%/50% between load and supply since items such as maintenance scheduling is caused by generation, telemetry is caused by both and used by both and price validation benefits the market, While other activities were more load related there was no method for determining an exact split so the 50%/50% was a reasonable alternative.

Power Systems Application Engineering
Coordinate all activities of the NYISO Power System Applications function to update and maintain the electric power system model used by the scheduling and dispatch software. Serve as Subject Matter Expert (SME) to support of ISO Energy Markets for the power system network model and Energy Management System software operation. Supports Energy Management System operation including State Estimator and Contingency Analysis and Grid Operations staff on a 365x24x7 on-call basis.

This cost center is allocated 50%/50% between load and supply based on its relationship to scheduling and communication between load and supply.

Commitment Analysis
Coordinate all activities of the NYISO Day-Ahead Market operations function to ensure that the New York Control Area will meet the next day load and reserve requirements in a reliable manner. Responsible for Subject Matter Expertise support of ISO Energy Markets for the Day-Ahead and the Real-Time load forecasting function and SCUC and RTS design and operation. Ensure successful integration of the bidding system with the Day-Ahead security analysis requirements of a NERC Security Coordinator. May perform commitment functions in the event of heavy volume and/or staff absences. Supports Real-Time Market operation and Grid Operations staff on a 24 / 7 call out basis.

This cost center is allocated 50%/50% between load and supply based on benefits to both parties.

Scheduling
Coordinate all activities of the NYISO scheduling function to ensure that the interconnected grid will support near-term system requirements. Assure successful integration of the bid / post system with NERC Tagging Procedures. Supervise the scheduling function in order to facilitate reliable operation of the New York energy marketplace. The scheduling function includes both the coordination of transmission faclity outages and the coordination of generating facility outages.

This cost center is allocated 50%/50% between load and supply based on communication between load and supply is facilitated via the scheduling activities although more cost could be allocated to load there was no basis for determining any other split.

Operations Performance & Analysis
Direct and manage the Operations Performance and Analysis Group and related activities in support of the Operations Department, coordinates the implementation of Operations process changes and provides for

overall coordination with other internal NYISO departments. This group is responsible for developing a number of monthly reports that describe the NYISO performance in the relability and market administration areas.

This cost center is allocated 50%/50% between load and supply based on benefits to both parties.

Operations Analysis and Services
Develops process and performs analysis to support the monitoring of performance of Grid Operations, Energy Market Operations, and TCC Market Operations. Performs activities to support other Operations' groups including the determination of certain data inputs for use in the energy markets.

This cost center is allocated 50%/50% between load and supply based on the services that impact both load and supply with no clear discernable allocation. This group appears to be more heavily load related but the data would not support a more specific allocation.

Market Design
Responsible for the enhancements to the market design rules which provide the underpinnings of the New York ISO's market operations.

This cost center is allocated 100% to load based on the fact that the market is operated to serve load.

Market and Employee Training
Supervise the training staff that develops and implements technical, market and compliance training for NYISO market participants, government stakeholders and NYISO employees. Review, evaluate and modify training programs as required to maintain the required compliance to NYISO Tariffs, Manuals, and Technical Bulletins; and ensure responsiveness to the needs of NYISO market participants.

This cost center is allocated 50%/50% between load and supply based on the fact that training is supplied to both load and supply (and to other market participants but without a way to allocate, assign or even collect those costs from others absent some new tariff related to training costs).

Energy Market Products
Develop customer requirements, oversee market design and project management for projects within the NYISO Energy Markets.

This cost center is allocated 100% to load based on the allocation of energy market costs to load.

Operations and Reliability Products
Develop customer requirements, oversee market design and project management for projects supporting NYISO Operations & Reliability.

This cost center is allocated 100% to load based on benefits of reliability accruing to load.

Department of Energy (Smart Grid) Project
The Department of Energy Smart Grid Investment Grant Project, funded by a matched $75M grant to the NYISO with the New York Transmission Owners as subawardees, will install Phasor Measurement Units, Phasor Data Concentrators, and Capacitors throughout the New York Control Area, and will provide visibility to the data collected via Situational Awareness Applications as well as other applications to be utilized to analyze that data.

This cost center is allocated 50%/50% between load and supply based on benefits to both parties.

System and Resource Planning

System and Resource Planning
Administers all System & Resource Planning responsibilities, reliability, economic, and environmental studies, and federal and state policy implementations in planning areas (SEP, RPS, etc.)

This cost center is allocated 100% to load based on the emphasis of planning and reliability are designed to assure load has capacity and energy to serve it. Thus load benefits and was assigned the costs. System Planning costs recovered 100% from load is also consistent with ISO-NE's Schedule 1

Load Forecasting and Energy Efficiency
Performs and oversees load and energy efficiency forecasting

This cost center is allocated 100% to load based on forecasting load and energy efficiency is solely load related thus all costs go to load.

Transmission Studies
Manages transmission studies and reliability compliance requirements

This cost center is allocated 50%/50% between load and supply based on the fact that transmission studies may be either load or supply related. No definitive allocation was possible although it is likely that more costs are load related but without detailed records to verify the presumption 50%/50% was a reasonable alternative.

Interconnection Projects
Manages ISO OATT interconnection process for generator and transmission projects, together with their capacity deliverability rights determinations.

This cost center is allocated 100% to supply based on the specific costs associated with supply.

System Modeling
Creates and maintains electric system facility models, and assures their accurate use in all NYISO SRP and Operations studies.

This cost center is allocated 100% to load based on since the benefits of these studies and models since they relate to load and reliability of the system.

Long Term Planning
Manages ISO OATT Comprehensive System Planning Process, RNA, CRP, and CARIS

This cost center is allocated 100% to load based on the benefits of long term planning are related to assuring long term capability to serve load reliably.

Reliability & Economic Planning
Administers ISO OATT Comprehensive System Planning Process, long term infrastructure planning and load and energy efficiency forecasting, ICAP requirement setting (IRM, LCR, Capacity Import Rights, etc.)

This cost center is allocated 100% to load based on its relationship to previous categories such as planning and load forecasting. There is a small portion of this cost center that is related to ICAP requirements, but the impact to the overall study is considered de minimis.

Interconnection Studies
Manages ISO OATT Interconnection Queue, coordinates with developers, and oversees interconnection related studies

This cost center is allocated 100% to supply based on the fact that all costs are incurred related to supply.

Shared Services

The following describes the allocation basis for if Shared Service costs were allocated using the load/supply split of the direct assigned costs they are allocated to, or if they are split 50%/50% between load and supply. The cost center groups that change between the two scenarios are also identified. This section only relates to the cost allocated to the physical markets. TCC and Virtual markets have no allocation to load or supply, but still receive an allocation of these shared services.

1 - Shared Services in Scenario Analysis ($66.2 million)

The following cost center groups are included in the scenario analysis. For each of these cost centers, in Scenario 1, they classified as "Other" and when allocated to each service category, the take on the load/supply split of the direct assigned cost in that service category. In Scenario 2, each of these cost centers are split 50%/50% between load and supply.

- Information Technologies
- Facilities and Safety (includes major capital spending)
- Infrastructure Products
- Business Intelligence Products
- General Counsel
- Strategic and Business Planning
- Market Mitigation and Analysis
- Corporate (primarily debt service and current year financing)

The reasoning for allocating these cost centers in two different ways is that many of the costs in these cost centers vary greatly by year depending on what the current focus is or if there are new markets or services. This is very true of the Products cost centers and the General Counsel cost center. Also some of these cost centers are quite large, specifically the Information Technology cost centers. Since an argument can rationally be made for allocating it either way, and that decision has a large impact on the outcome of the study, it made sense to compare the results both ways.

2 - Shared Services Allocated Equally to Load and Supply ($13.4 million)

The following cost centers are split 50% / 50% between load and supply in both scenarios.

- Customer Settlements and related activities
- Quality Control and Quality Assurance
- Corporate Credit
- Customer Relations and Customer Support
- Financial Systems Products (relates to Settlements)
- External and Regulatory Affairs
- Communications and Committee Support

The cost centers that are allocated 50% / 50% between load and supply in both scenarios are customer related costs. Since the number of load serving customers is comparable to the number of generating customers, it made sense to split these costs equally.

3 - Shared Services Allocated 100% to Load ($400,000)

The following cost center is allocated 100% to Load in both scenarios.

- Consumer and State Relations

This category is allocated 100% to Load based on its relationship with end use consumers, which is 100% load.

4 - Shared Services Classified as Other ($17.6 million)

The following cost centers are classified as “Other” in both scenarios. These costs will take on the load/supply split of the direct assigned costs of the service category they are allocated to. For example, the share of these costs that are allocated to the Capacity Markets will have a 50% / 50% split between load and supply, but the portion that is allocated to the Demand Response service category would be 100% to Load. The basis for allocating these cost centers using the assignment of direct costs is they are generally corporate overhead type costs and traditional cost allocation theory is that these cost should be allocated using the costs that have been direct assigned.

- Executive Management
- Finance and Accounting
- Human Resources
- Enterprise and Customer Services (primarily Insurance)
- Internal Audit