PUCN

Public Utilities Commission of Nevada

Cost of Service Studies

April 14, 2016

COST OF SERVICE STUDIES ("COSS")

- Used to reasonably allocate costs (revenue requirement) incurred by utility amongst customer classes
- 2 Types of COSS
  - Embedded – Look at costs from a historical perspective (some costs that were incurred 15+ years ago)
  - Marginal – Look at costs from a theoretical perspective of producing an additional unit of energy and what does it cost to produce that unit. (Argued to be a better price signal for current behavior)

Marginal Cost of Service Studies - Purpose and Rate Setting Goals

- The customers that cause the costs pay for those costs=Cost Causation
  - Nevada uses Marginal Cost Pricing to determine the fair share of electric service that each class of customer pays – Limit interclass and intraclass subsidies
  - Marginal costing estimates the cost to provide:
    - the next unit of Generation, Transmission, and Distribution demand
    - the next kWh of Energy (including fuel & purchase power cost),
    - the facilities to hook up the next customer (Facilities, Services, Meters), and
    - the cost to provide Billing and Customer Service to that customer
  - NV Energy designs rates to collect the PUCN approved overall and class revenue requirements – enhance revenue stability

Regulations: The applicable regulations have been in place since 1982.

NAC 704.660 Consideration of marginal cost of service in determining class revenue requirements. **(**NRS 703.025**,** 704.210**)** The Commission will consider a utility's marginal (incremental) cost of service to each class of customer in determining the revenue required from that class.

[Pub. Service Comm'n, Gen. Order 33 § 2.0, eff. 9-17-82]

NAC 704.662 Rate design based on marginal cost of service. (NRS 703.025**,** 704.210**)**

1. The rates charged by the utility for supplying electricity to customers of a particular class must reflect the marginal (incremental) cost of serving that class, including any seasonal or hourly differences in the cost of the service, *unless* the Commission determines, in a proceeding to establish or change the rate, that:

(a) In the case of a proposed rate which reflects seasonal differences in the cost of service:

(1) Those differences are so insignificant …; or

(2) Application of the proposed rate would unreasonably affect the utility's financial condition.

(b) In the case of a proposed rate which would reflect hourly differences in the cost of service, the cost of providing meters …would be greater than the benefits of conservation of electric energy and efficient use of facilities and resources which would be obtained from use of the proposed rate.

(c) In any case:

(1) The rate would not be equitable; or

(2) The expected level of understanding or acceptance of the rate by the customers of the class to which the rate would apply is such that the rate would not likely serve the purpose of this regulation...

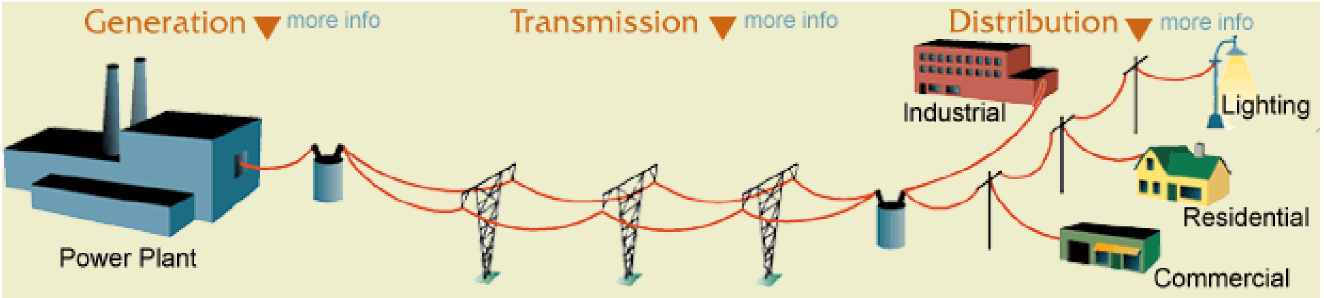
Marginal Cost Studies

- How is the marginal cost of service determined and presented?
  - Building Block approach that is summarized by function, class of customer, and Time-Of-Use (TOU) period
  - Cost of the next unit: next customer extension; next bill; next kW of generation, transmission and distribution capacity; next kWh of energy
  - Primary Inputs include:
    - ❑ Planning (forecast) and Accounting (historical) data
    - ❑ Customer Weighting Factor Study
    - ❑ Hourly Cost Responsibility Factors (Allocators)
      - Class hourly load requirements (Load research)
      - Forecast PROMOD modeling data
      - Assumption of a future rate effective year
- Calculations create hourly costs by function and class for the future rate effective year adjusted by class for losses

Basic Steps in Marginal Cost of Service and Rate Design –Functionalized and Classified

- Costs by Function
  - Generation
  - Transmission
  - Distribution (Facilities)
  - Customer
- Classified into Variable, Fixed, and Customer
- Costs are developed by Class and by Hour
- Costs are then compiled by Time-of-Use ("TOU") period
- Marginal costs are reconciled to an embedded revenue requirement and allocated to customer classes using Consumption (total usage), Peak, and Customer count data.

Marginal Cost – Long Run Cost Impacts of Unit Demand Changes on Each Part of Our System



Generation
Coal, gas, water, geothermal, nuclear, oil, diesel, solar, or wind.

Marginal Generation Unit Demand Cost is based on the least capital cost capacity addition (CT)

Annual Unit Demand Cost assigned to hours based on LOLP

Energy
Internally generated and purchased energy.

Marginal Energy Costs generated for 8760 hours in PROMOD economic dispatch. They are load weighted and loss-adjusted by class and TOU period.

Transmission
High voltage transportation to load centers.

Typically In the past:
Marginal Transmission Unit Cost:

Regression Methodology of 17 yr hist & 3 forecast plant & loads

Annual Unit Demand Cost assigned to hours based on POP

Distribution
Lower voltage delivery to business & residential customers.

Demand Costs:

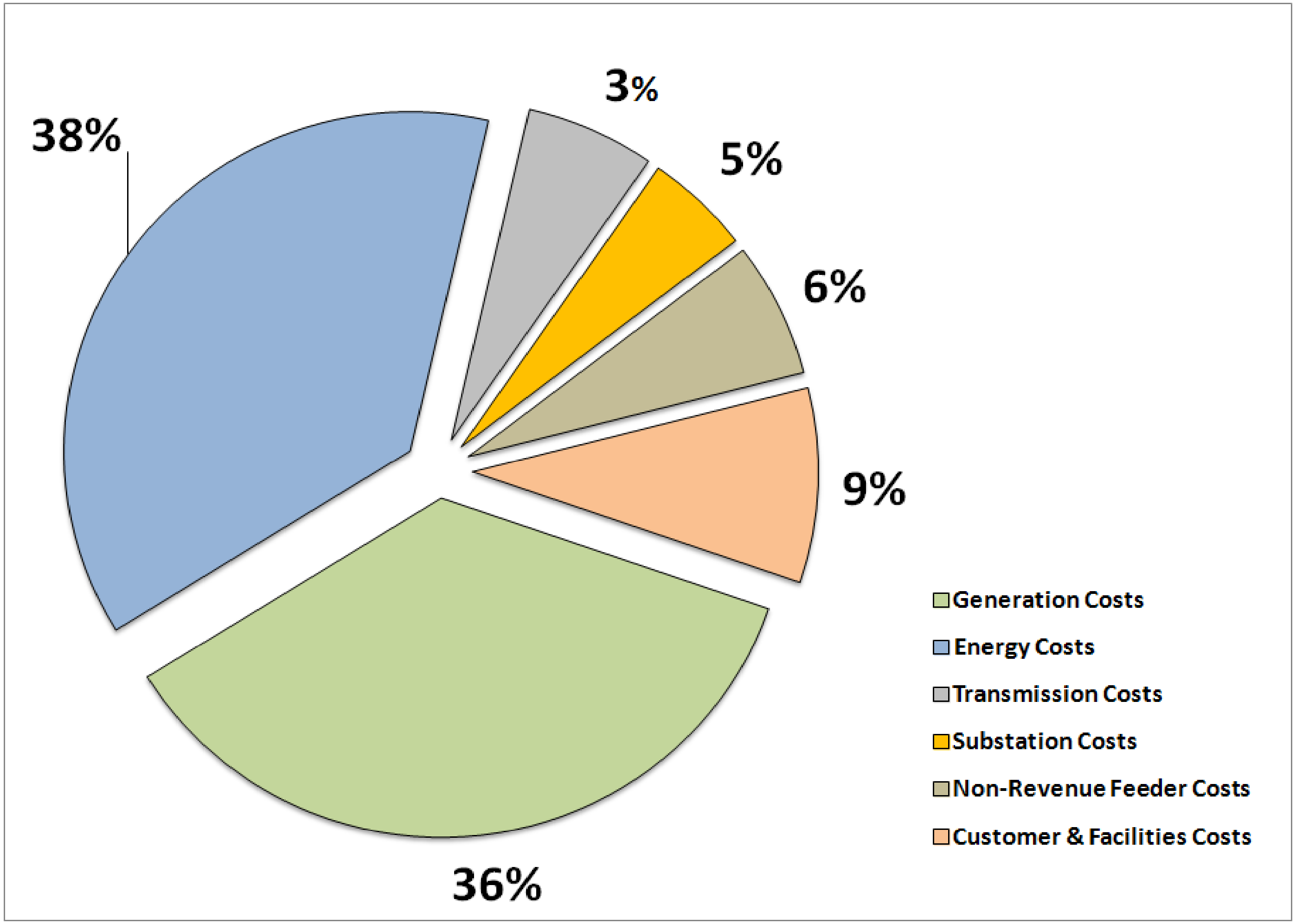
Regression Methodology of 17 yr hist & 3 forecast plant & loads

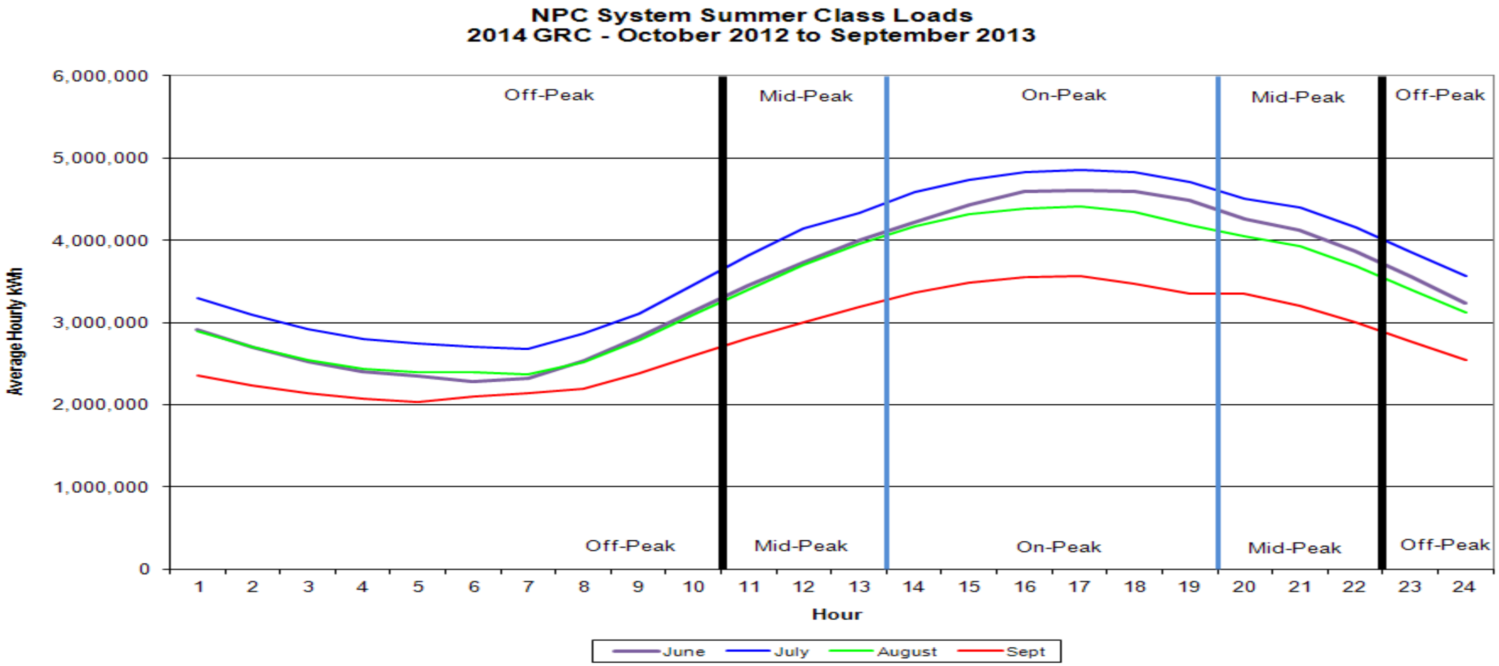
Annual Unit Demand Cost assigned to hours based on POP

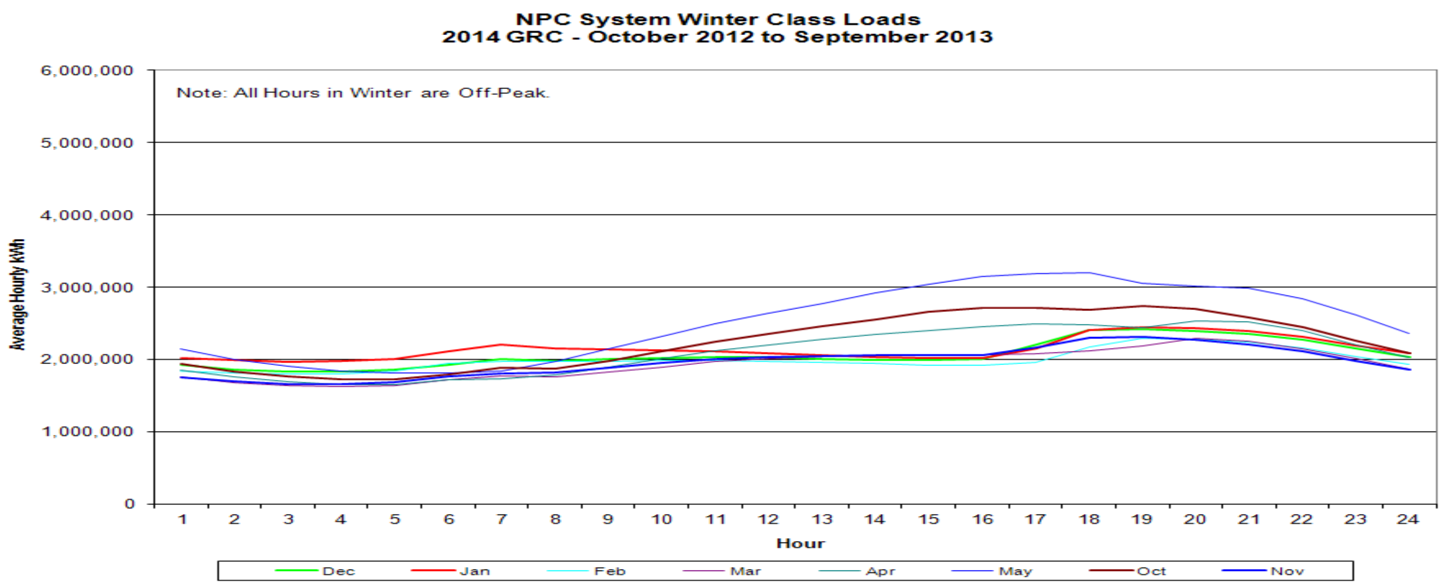
Facilities Costs:
Marginal Facilities Cost, by class, from recent work order data base and some customer-specific investments are not differentiated by TOU.

Customer Costs:
Meter Costs, Customer Accounting and Customer Services Costs are not differentiated by TOU

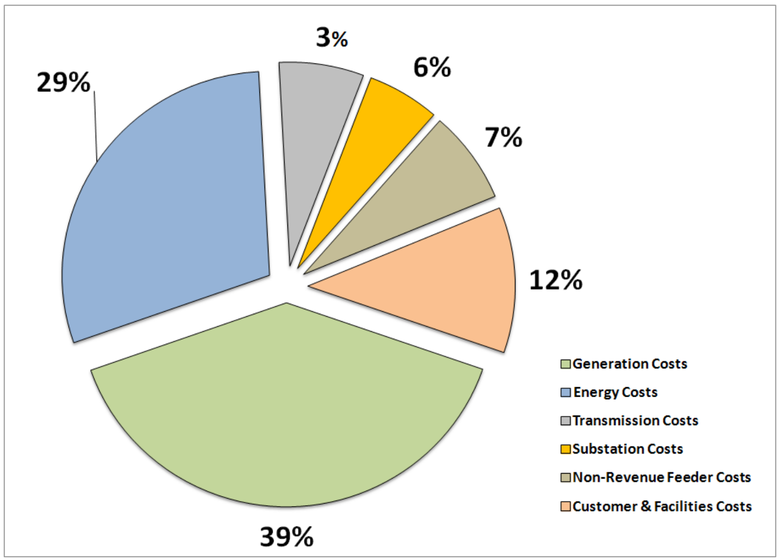
NPC System Costs by Category

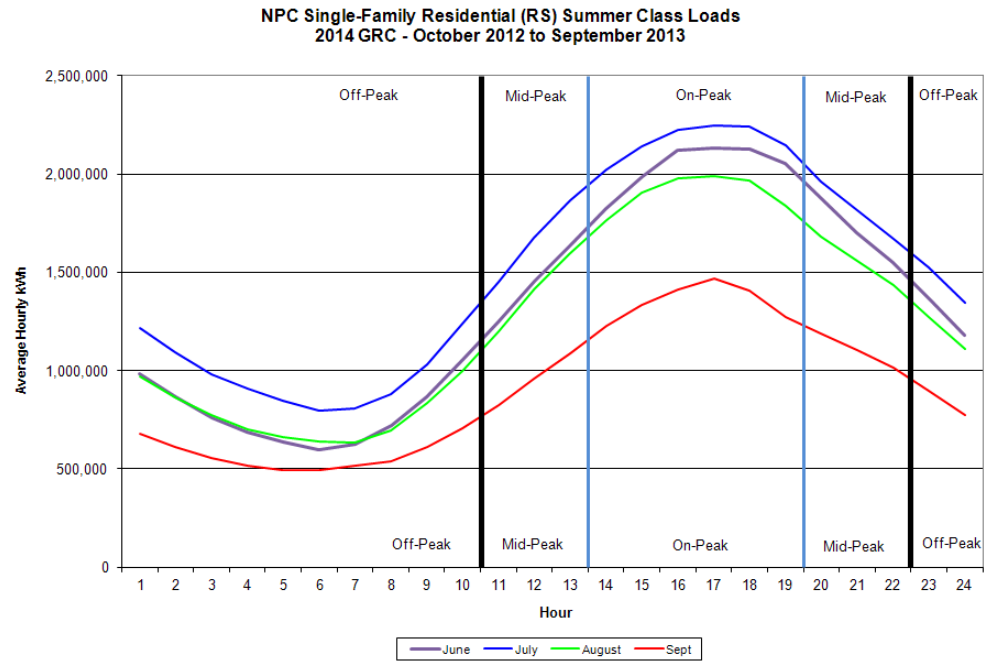


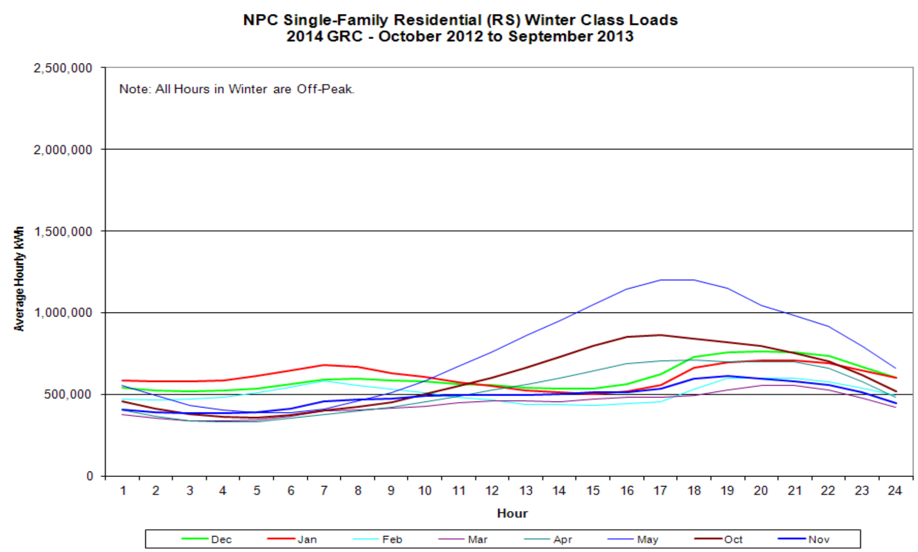

NPC System Summer Class Loads
2014 GRC - October 2012 to September 2013
6,000,000
5,000,000
4,000,000
3,000,000
2,000,000
1,000,000
0
Average Hourly kWh
Off-Peak
Mid-Peak
On-Peak
Mid-Peak
Off-Peak
Off-Peak
Mid-Peak
On-Peak
Mid-Peak
Off-Peak
1 2 3 4 5 6 7 8 9 10 11 12 13 14 15 16 17 18 19 20 21 22 23 24
Hour
June
July
August
Sept


NPC System Winter Class Loads
2014 GRC - October 2012 to September 2013
6,000,000
5,000,000
4,000,000
3,000,000
2,000,000
1,000,000
0
Average Hourly kWh
Note: All Hours in Winter are Off-Peak.
1 2 3 4 5 6 7 8 9 10 11 12 13 14 15 16 17 18 19 20 21 22 23 24
Hour
Dec
Jan
Feb
Mar
Apr
May
Oct
Nov

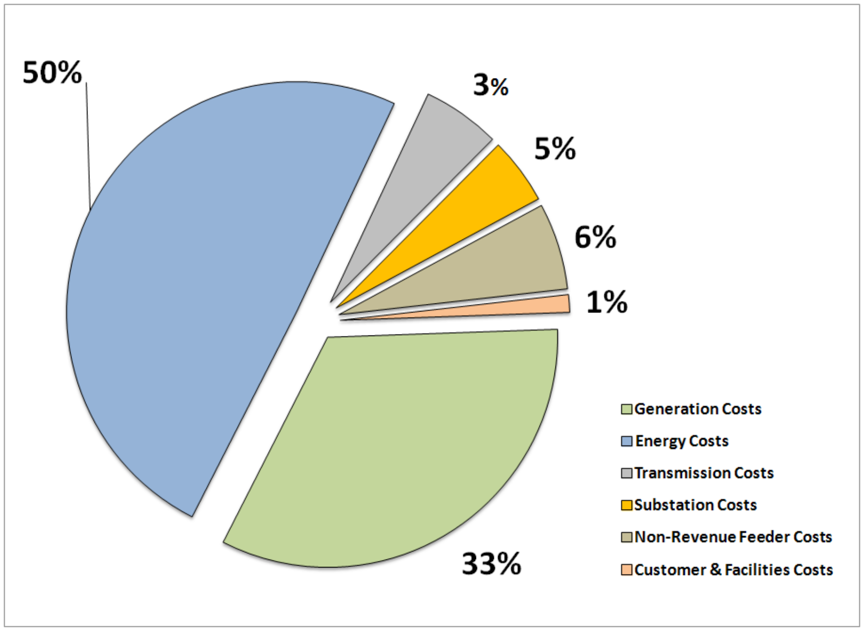
Marginal Cost & Loads – Residential

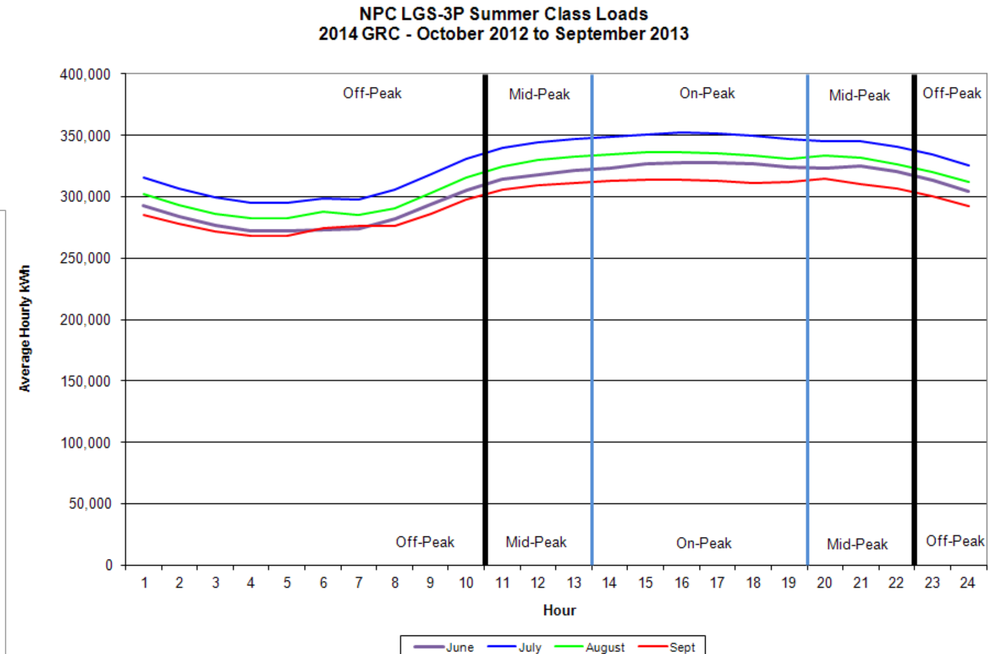


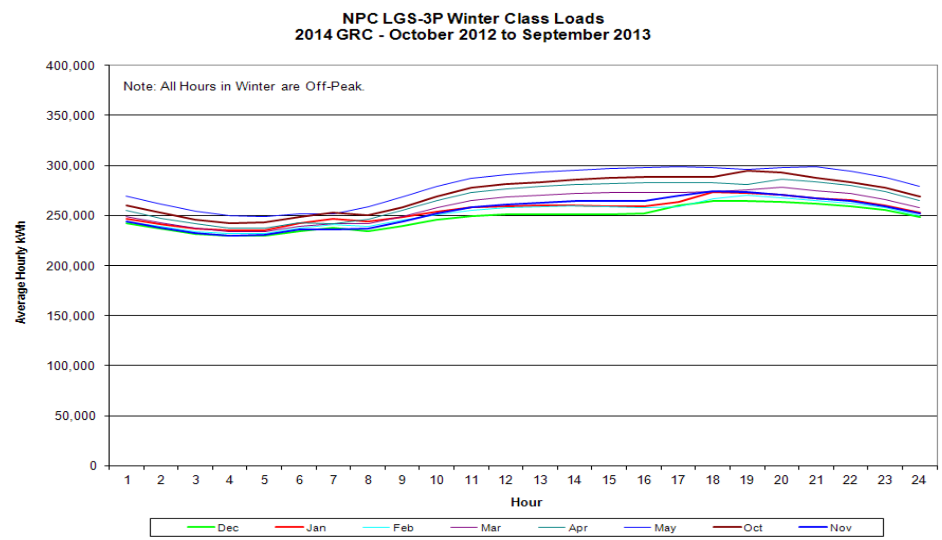




Marginal Cost & Loads – LGS-3P







Customer Cost Inputs

- Meter investment, Meter O&M
- Customer account expenses (901–904)
  - Customer accounting and collection activities including:
    - Supervision
    - Meter reading
    - Customer records
    - Uncollectible accounts
- Customer information expenses (907–909)
  - Customer service and information activities encouraging safe use and conservation including:
    - Supervision
    - Customer assistance
    - Informational and instructional advertising
- Adders and carrying charges

Customer Weighting Factor Study
Overview

- Method of allocating customer accounts and service expenses to customer classes:
    - Customer Accounts Expense (FERC 901-905);
    - Customer Services Expense (FERC 907-910).
- Departmental Surveys are completed to individually identify customer classes being served by each area.
- Weights are developed on an expense per customer basis relative to residential classes (Residential weight = 1.00).

Marginal Transmission & Distribution Demand

- Cost causation –determined by Probability of Peak (POP) cost responsibility factor
- Those hours in year that are 90% or greater of annual peak are determined to contribute to requirement for additional T&D capacity.
- Classes with load requirements that correspond to the peak hours will be assigned greater T&D costs.
- Based on a regression of 17 yr historical & 3 yr forecast plant and loads.
- Same methodology as previously approved with 2 more historical years of data.

Calculation of POP

- Same Methodology as previously approved
- 10 years of historical hourly system sales
- 1 year of forecast hourly system sales (PROMOD)
  - Generally only one year is used as all forecast years utilize the same base load shape.
- Probability of Peak is calculated for every hour in every year to normalize for load growth.
- Probabilities calculated assuming normal distribution.

Marginal Generation Demand

- Same methodology as previously approved
- Installed cost of generation is based on the estimated cost of a combustion turbine.
- Cost causation determined by Loss of Load Probability (LOLP) cost responsibility factor.
  - Multiple years of forecast PROMOD data
  - Those hours of the year with loads likely to exceed available capacity result in a probability that load will be lost and contribute to the requirement for additional Generation capacity.
- Classes with load requirements that correspond to the hours with higher probability of lost load will be assigned greater Generation demand costs.

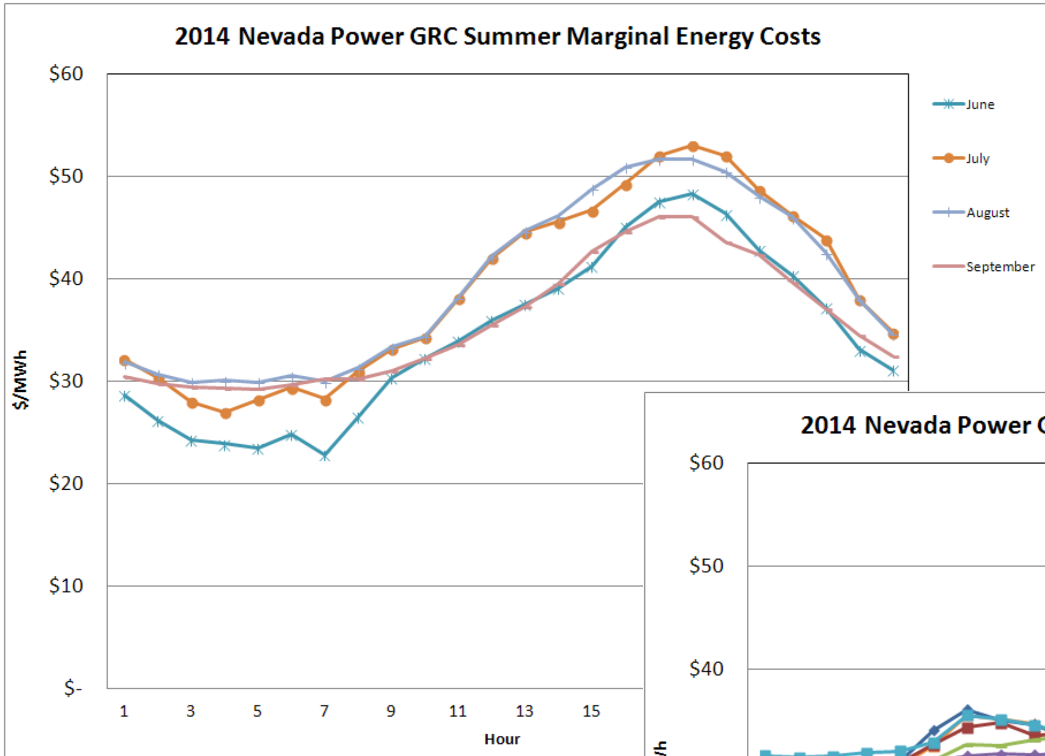
Calculation of LOLP

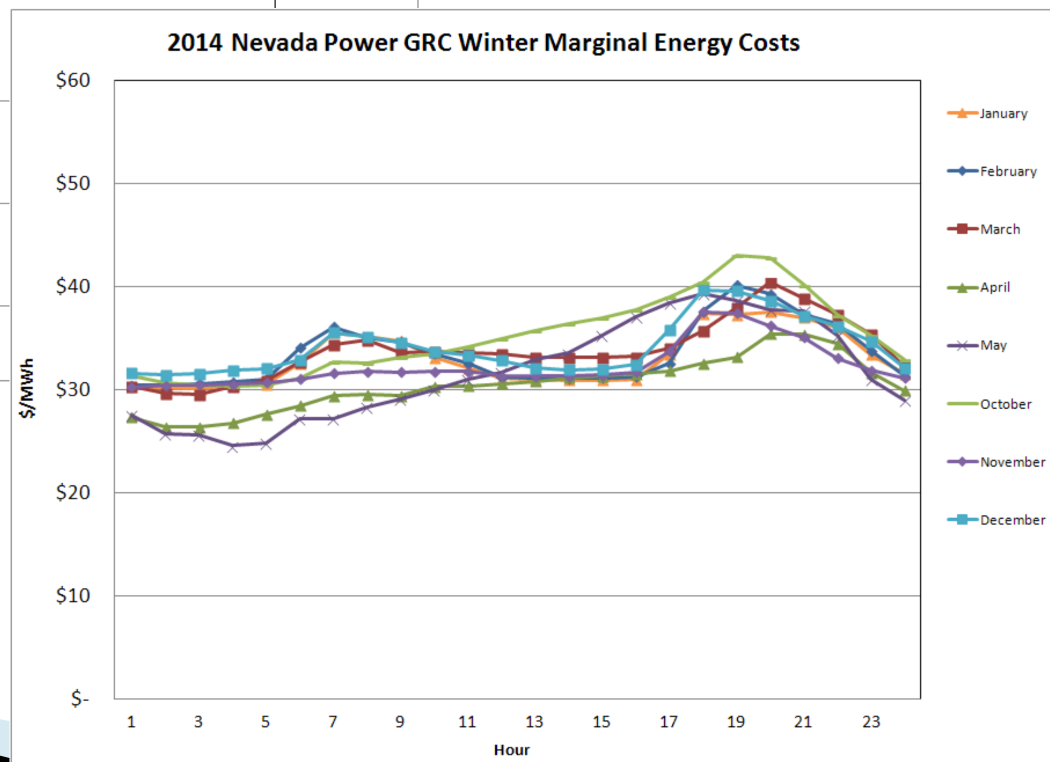
- Typically 3-5 years of PROMOD data is used
  - Period selected will precede the year of new generation addition(s)
- Calculation
  - Hourly values averaged over the period and mapped to test year
    - by Month, Day of Week and Hour
  - Sum-normalized in test year (100%)
    - Creates percent of total LOLP value for each hour

Marginal Energy Costs (MEC)

- Cost causation determined by hourly rate effective period (usually three forecast years) MEC
- PROMOD data provided by Resource Planning Department
- Adjusted for losses by class dependent on voltage level
- Classes with hourly sales that correspond to hours with higher MEC costs will be assigned relatively higher marginal energy revenues in the MCS, on a $/kWh basis

Marginal Energy Costs at NPC (Seasonal)





Reconciliation Process

- Marginal costs are reconciled to the target revenue requirement, which is the revenue requirement adjusted for class revenues not developed in the reconciliation. This ensures the Company only collects the actual revenue requirement in proposed rates.
- Reconciliation is done by function on an Equal Percent of Marginal Cost (“EPMC”) basis.
- The EPMC method is objective and fair in its application – if a customer class is responsible for 10% of the marginal cost it is reasonable to assign to it 10% of the revenue requirement.
- Distribution and Transmission are reconciled separately.
- Generation & Energy are reconciled together because of their interrelated nature.

Line No.	Class	Total Distribution Services	Percent of Total	Adjustment for Other Revenue Assigned to Specific Classes	Cost Based Class Revenue, before CSF & After Other Revenue	Adjustment for X Class Cust Spec. Facilities	Distribution Cost Based Class Revenue	Transmission Demand	Percent of Total	Transmission Cost Based Class Revenue	Generation Demand	Energy before Hoover B and WAPA adjustment	Generation Demand & Energy before Hoover B and WAPA adjustment	Percent of Total	Energy Cost Based Class Revenue, before Adjustments	WAPA, Hoover B Credit, & Res. Plan Recovery	Energy Cost Based Class Revenue
		Distribution Marginal Cost Revenues						Transmission Marginal Cost Revenues			Generation & Energy Marginal Cost Revenues						
	---B---	---C---	---D---	---E---	---F---	---G---	---H---	---I---	---J---	---K---	---L---	---M---	---N---	---O---	---P---	---Q---	---R---
8	RM	$ 68,877	12.89%	$ (1,930)	$ 48,042	$ -	$ 48,042	$ 16,973	10.86%	$ 18,969	$ 106,359	$ 92,626	$ 198,986	10.44%	$ 166,717	$ (607)	$ 166,110
9	RS	275,581	51.56%	(2,256)	197,684	-	197,684	74,210	47.48%	82,937	442,390	331,860	774,249	40.61%	648,695	$ (2,150)	646,544
10	LRS	938	0.18%	(1)	679	-	679	305	0.20%	341	1,789	1,641	3,430	0.18%	2,874	$ (11)	2,863
11	GS	37,946	7.10%	(406)	27,125	-	27,125	3,532	2.26%	3,947	20,548	31,110	51,658	2.71%	43,281		43,281
12	LGS-1	67,120	12.56%	(107)	48,590	-	48,590	22,447	14.36%	25,087	130,007	169,742	299,749	15.72%	251,141		251,141
13	LGS-2S	34,471	6.45%	(2)	25,007	-	25,007	12,989	8.31%	14,516	76,230	108,315	184,545	9.68%	154,619		154,619
14	LGS-2P	866	0.16%	-	628	-	628	366	0.23%	409	2,178	3,626	5,803	0.30%	4,862		4,862
15	LGS-2T	-	0.00%	-	-	-	-	-	0.00%	-	-	-	-	0.00%	-		-
16	LGS-3S	13,395	2.51%	(0)	9,718	-	9,718	5,802	3.71%	6,484	34,706	50,559	85,266	4.47%	71,439		71,439
17	LGS-3P	26,899	5.03%	(0)	19,516	-	19,516	12,275	7.85%	13,718	74,187	111,003	185,190	9.71%	155,159		155,159
18	LGS-3T	1,965	0.37%	-	1,426	-	1,426	2,254	1.44%	2,520	12,689	19,608	32,297	1.69%	27,060	$ (799)	26,261
19	LGS-XS	62	0.01%	-	45	23	68	61	0.04%	68	374	435	809	0.04%	677		677
20	LGS-XP	2,267	0.42%	-	1,645	867	2,512	1,993	1.27%	2,227	12,100	17,495	29,595	1.55%	24,796		24,796
21	LGS-XT	201	0.04%	-	146	649	795	2,898	1.85%	3,239	17,611	26,328	43,939	2.30%	36,813	$ -	36,813
22	LGS-2S-WP	318	0.06%	-	231	-	231	29	0.02%	33	205	857	1,062	0.06%	890		890
23	LGS-2P-WP	148	0.03%	-	107	-	107	42	0.03%	47	247	591	838	0.04%	702		702
24	LGS-2T-WP	-	0.00%	-	-	-	-	-	0.00%	-	-	-	-	0.00%	-		-
25	LGS-3S-WP	65	0.01%	-	47	-	47	8	0.01%	9	31	324	355	0.02%	297		297
26	LGS-3P-WP	160	0.03%	-	116	-	116	42	0.03%	47	218	680	898	0.05%	752		752
27	LGS-3T-WP	-	0.00%	-	-	-	-	-	0.00%	-	-	-	-	0.00%	-		-
28	SL	2,894	0.54%	(4)	2,095	-	2,095	84	0.05%	94	772	6,777	7,549	0.40%	6,325		6,325
29	RS-Pal	86	0.02%	(0)	62	-	62	0	0.00%	0	2	38	40	0.00%	34	$ (0)	34
30	GS-Pal	251	0.05%	(0)	182	-	182	0	0.00%	0	7	123	130	0.01%	109		109
31																	
32	TOTAL	$ 534,509	100%	$ (4,707)	$ 383,092	$ 1,539	$ 384,631	$ 156,311	100.00%	$ 174,692	$ 932,651	$ 973,738	$ 1,906,389		1,597,243	$ (3,568)	$ 1,593,675
33	Functionalized Rev Requirements:			$ 384,631	....					$ 174,692		$ 624,890	Gen RR				
34	Adjustments:		Less Cust. Spec Revenues	$ 383,092					Transmission Reconciliation Factor	111.76%		$ 968,785	Eng RR	$ 3,568	Plus WAPA & Hoover B Cr.		
35			Plus Other Revs	$ 387,799	Other Revenue from: misc. revenues, returned check, power pedestal, and misc. damage							$ 1,593,675	Total G&E RR	$ 1,597,243	Total Adjusted RR		
36					72.6%	Dist Reconciliation Factor								83.60%	G&E Reconciliation Factor		
37																	

38	Class	Sum of Functional Cost Based Class Revenue Before PF and AF&M	Percent of Total	Power Factor Adjustment	Additional Facilities & Maintenance (AF&M) Contract Revs	Sum of Functional Cost Based Class Revenue (To Page 7)	Capped Class Revenue Requirement (From Page 7)	Revenue Proof	Percent of Total	Rounding	Overall Effective Rate (all revenues)	Overall Effective Rate (not including Rule 9 Facilities Revenue)					
39	----B2----	----C2----	----D2----	----E2----	----F2----	----G2----	----H2----	----I2----	----J2----	----K2----	----L2----	----M2----	Verification of Revenue Requirement			----Q2----	----R2----
40	RM	$ 233,122	10.83%	$ -	$ -	$ 233,122	$ 241,295	$ 241,300	11.20%	$ 5	$ 0.12328	$ 0.11840					
41	RS	927,166	43.06%	-	-	927,166	887,856	887,859	41.22%	3	0.12871	0.11981	Total Sales Revenue (pg 1)			$ 2,171,305	
42	LRS	3,884	0.18%	-	-	3,884	4,020	4,020	0.19%	(0)	0.11604	0.11007	Revenue Credits (pg 1)			$ (18,307)	
43	GS	74,353	3.45%	-	-	74,353	75,100	75,098	3.49%	(1)	0.11097	0.08664				$ 2,152,998	
44	LGS-1	324,818	15.09%	58	1	324,877	336,266	336,264	15.61%	(3)	0.09188	0.08872					
45	LGS-2S	194,142	9.02%	231	-	194,373	201,188	201,188	9.34%	0	0.08571	0.08377	Revenue from Proposed Rates			$ 2,154,164	
46	LGS-2P	5,899	0.27%	18	-	5,917	6,124	6,124	0.28%	0	0.07602	0.07555	Addin Rev. Req. Adjustment			$ -	
47	LGS-2T	-	0.00%	-	-	-	-	-	0.00%	-			Add in Rev. Credit Adjustments.			$ 17,146	
48	LGS-3S	87,641	4.07%	118	-	87,759	90,835	90,836	4.22%	0	0.08251	0.07836				$ 2,171,309	
49	LGS-3P	188,392	8.75%	230	219	188,842	195,463	195,462	9.07%	(1)	0.07938	0.07869	Add Rounding			$ 4	Check (diff s/b=0) >
50	LGS-3T	30,206	1.40%	46	-	30,252	30,140	30,140	1.40%	(0)	0.06876	0.06829	Total Revenue Requirement (before adjustments)			$ 2,171,305	$ -
51	LGS-XS	813	0.04%	2	-	815	752	752	0.03%	(0)	0.07983	0.07739					
52	LGS-XP	29,535	1.37%	99	75	29,709	30,750	30,751	1.43%	0	0.07946	0.07722					
53	LGS-XT	40,847	1.90%	21	29	40,897	41,854	41,854	1.94%	(0)	0.07107	0.06997	Total, Cost Based, Col C2			$ 2,152,998	
54	LGS-2S-WP	1,153	0.05%	6	-	1,159	1,094	1,094	0.05%	0	0.05383	0.04802	Add Power Factor (PF) & AF&M			$ 1,161	
55	LGS-2P-WP	857	0.04%	3	-	860	890	890	0.04%	(0)	0.06550	0.06454	Add Non-PF & Non-AF&M Rev Credit			$ 17,146	
56	LGS-2T-WP	-	0.00%	-	-	-	-	-	0.00%	-							
57	LGS-3S-WP	354	0.02%	4	-	357	370	370	0.02%	(0)	0.04852	0.04541				$ 2,171,305	
58	LGS-3P-WP	916	0.04%	1	-	917	950	950	0.04%	0	0.06008	0.05799			Check: s/b=0 >>	$ -	
59	LGS-3T-WP	-	0.00%	-	-	-	-	-	0.00%	-							
60																	
61	SL	8,514	0.40%	-	-	8,514	8,812	8,812	0.41%	0	0.05707	0.05680					
62	RS-Pal	96	0.00%	-	-	96	99	99	0.00%	(0)	0.11340	0.04263					
63	GS-Pal	291	0.01%	-	-	291	301	301	0.01%	0	0.10733	0.04277					
64																	
65	TOTAL	$ 2,152,998	100.00%	$ 836	$ 325	$ 2,154,160	$ 2,154,160	$ 2,154,164	100.00%	$ 4	$ 0.10568	n/a					

Based on NPC 2014 GRC:

Residential Basic Service Charge Costs

System Picture

Customer

Rule 9 Facilities

Primary Distribution Facilities

	Customer	Rule 9 Facilities	Primary Distribution Facilities
Marginal Cost Components	**Marginal Customer Costs** Meter Meter Reading & Billing (Customer Service and Accounting Exp.)	**Marginal Facilities (i.e. Rule 9) Costs** Service Drop 120/240 V Service Transformer Extension of Primary Distribution (usually Lateral - 13.8 kV)	**Marginal Distribution Demand** Backbone Feeder (Mainline) - 24.9 kV Distribution Substation
Marginal Cost Allocators	Typical Meter by Class (from Meter Shop) Customer Weighting Factor Study (for Customer Service & Accounting)	Typical Facilities by Class (from Facilities Study)	POP (Probability of Exceeding 90% of System Peak)
Reconciled Cost	\$5.21	\$10.12	\$17.24
Cumulative % Approved RS BSC of \$12.75 Recovers Cost Based Revs	100%	83.2%	0.0%

LGS-3S

Line No.	Component	Billing Units	Marginal Cost (MC) Revenue	Marginal Cost (MC) Rate	Reconciled MC & IRR Revenue	Reconciled MC & IRR Rate	**Proposed Rates**	Proof of Revenue	Percent of Revenue	Line No.
	---B---	---C---	---D---	---E---	---F---	---G---	---H---	---I---	---J---	
9										9
10	Distribution Services									10
11	Customer (per Cust, per Mo.)	1,920	$ 354	$ 184.60	$ 260	$ 135.58	$ 135.60	$ 260	0.3%	11
12	Separate Bill (per Bill, per Mo.)								0.0%	12
13	Addtl Meter Charge (per Meter, per Mo.)	180	$ 6	$ 32.02	$ 4	$ 23.52	$ 23.52	$ 4	0.0%	13
14	Fac Chg (per kW, per Mo.)	2,762,594	$ 1,635	$ 0.59	$ 1,201	$ 0.43	$ 3.44	$ 9,503	10.4%	14
15	Primary (per kW, per Mo.)	2,762,594	$ 11,317	$ 4.10	$ 8,311	$ 3.01				15
16	Total Distribution Services		$ 13,312		$ 9,777					16
17										17
18	Transmission Demand (per kW)									18
19	On Peak (per kW, per Mo.)	805,030	$ 4,975	$ 6.18	$ 5,800	$ 7.20				19
20	Mid Peak (per kW, per Mo.)	811,640	$ 577	$ 0.71	$ 673	$ 0.83				20
21	Off Peak (per kW, per Mo.)		$ 0		$ 0					21
22	Other (per kW, per Mo.)	1,391,613	$ 10	$ 0.01	$ 12	$ 0.01				22
23	Total Transmission, per kW		$ 5,563		$ 6,485					23
24										24
25	Generation Demand (per kW)						T&G			25
26	On Peak (per kW, per Mo.)	805,030	$ 26,494	$ 32.91	$ 22,228	$ 27.61	$ 18.73	$ 15,078	16.5%	26
27	Mid Peak (per kW, per Mo.)	811,640	$ 8,429	$ 10.39	$ 7,072	$ 8.71	$ 3.50	$ 2,841	3.1%	27
28	Off Peak (per kW, per Mo.)		$ 142		$ 119				0.0%	28
29	Other (per kW, per Mo.)	1,391,613	$ 200	$ 0.25	$ 167	$ 0.21	$ 0.60	$ 835	0.9%	29
30	Total Generation, per kW		$ 35,265		$ 29,587					30
31										31
32	Energy (per kWh)									32
33	On Peak (per kWh, per Mo.)	113,060,688	$ 6,522	$ 0.05769	$ 5,472	$ 0.04840	$ 0.09633	$ 10,891	11.9%	33
34	Mid Peak (per kWh, per Mo.)	110,932,826	$ 5,665	$ 0.05106	$ 4,753	$ 0.04284	$ 0.06898	$ 7,652	8.4%	34
35	Off Peak (per kWh, per Mo.)	198,298,141	$ 8,220	$ 0.04145	$ 6,897	$ 0.03478	$ 0.04851	$ 9,619	10.5%	35
36	Other (per kWh, per Mo.)	676,752,294	$ 29,815	$ 0.04406	$ 25,015	$ 0.03696	$ 0.05140	$ 34,785	38.0%	36
37	Total Energy, per kWh	1,099,043,950	$ 50,222	$ 0.04570	$ 42,136	$ 0.03834				37
38										38
39	Adjustments:									39
40	PF-Seasonal Smr & Wntr Revs				$ 118					40
41	Add. Fac. & Maintenance				$ -					41
42	Total Adjustments				$ 118			$ 118	0.1%	42
43										43
44	Cost Based Total		$ 104,362		$ 88,103	$ 0.08016				44
45										45
46	Interclass Rate Rebalancing (IRR):				$ 3,485					46
47										47
48	Total		$ 104,362	$ 0.09496	$ 91,588	$ 0.08333		$ 91,588	100.0%	48
49	Checks, s/b zero:		$ -		$ -	$ -	rounding:	$ (0)		49
50										50
51	**RATE SUMMARY**									51
52					Present	Cost	Proposed	Percent		52
53					Rate	Based Rate	Rate	Change		53
54	BTER				$ 0.04705	$ 0.03834	$ 0.04705	0.0%		54
55	Interclass Rate Rebalancing (IRR, per kWh):						$ 0.00317			55
56										56
57	Distribution Charges									57
58	Basic Service Charge, per Bill				$ 202.50	$ 135.58	$ 135.60	-33.0%		58
59	Addtl. Meter Charge, per Meter:				$ 57.87	$ 23.52	$ 23.52	-59.4%		59
60	Facilities Charge, per kW:				$ 3.38	$ 3.44	$ 3.44	1.8%		60
61										61
62	T & G Demand Charges, per metered kW									62
63	All Periods, or:				$ -	$ -	$ -	0.0%		63
64	On-Peak				$ 16.30	$ 34.81	$ 18.73	14.9%		64
65	Mid-Peak				$ 2.59	$ 9.54	$ 3.50	35.1%		65
66	Other				$ 0.55	$ 0.22	$ 0.60	9.1%		66
67										67
68				Present	Cost	Proposed Rate				68
69	Total Energy Charges (BTGR & BTER):			Rate	Based Rate	w/o IRR	with IRR			69
70	All Periods, or:			$ -	$ -	$ -	$ -	0.0%		70
71	On Peak (per kWh, per Mo.)			$ 0.08624	$ 0.04840	$ 0.09316	$ 0.09633	11.7%		71
72	Mid Peak (per kWh, per Mo.)			$ 0.06724	$ 0.04284	$ 0.06581	$ 0.06898	2.6%		72
73	Off Peak (per kWh, per Mo.)			$ 0.04892	$ 0.03478	$ 0.04534	$ 0.04851	-0.8%		73
74	Other (per kWh, per Mo.)			$ 0.05510	$ 0.03696	$ 0.04823	$ 0.05140	-6.7%		74
75										75
76	Overall effective rate (per kWh):			$ 0.08193			$ 0.08333	1.7%		76
								1.7%	check	

Mechanics of Rate Design – Demand

- In setting demand rates we attempt to obtain reasonable levels of change in demand rates while maintaining cost-based price signals.
- All Commercial Classes have Facilities demand charges recovering Facilities and Distribution Demand costs on a maximum kW basis.
- For Commercial TOU classes, all Transmission Demand costs and a large portion of Generation Demand costs are recovered through TOU demand charges based on a TOU kW basis.
- A certain portion of Generation Demand costs are recovered in the Energy Rate with an increasing portion of the Generation Demand costs that continue to be recovered in energy rates assigned to the TOU period from which they originate (primarily the summer-on and mid-peak periods).

Mechanics of Rate Design – Energy

- Energy Rates are set in total (BTGR & BTER), from which the BTER is then removed to derive the BTGR component.
- For non-TOU classes, a single energy rate is set which recovers all energy-related costs, and any fixed or demand costs not recovered in the BSC and demand rates (if applicable).
- TOU kWh charges, with the exception of the two-part Residential and GS classes, are set for each TOU period to recover the cost-based energy revenue by TOU period including any Generation Demand costs not recovered in demand charges.

NVE Process for MCS with Separate NEM/DG Residential and Small GS Classes

- Start with the last approved MCS
  - 2014 NPC (Docket No. 14-05004)
  - 2013 SPPC (Docket No. 13-06002)
- Update SPPC Billing Determinants to most current available
  - Source Statement G -- Twelve months ended March 31, 2015
- Use Billing Determinants from the 2014 NPC GRC Certification filing
- Update Marginal Energy Costs, LOLPs, and POP
- Use total hourly load requirements and hourly delivered sales for NEM/DG customers
  - Representative shapes derived from actual data and NREL data scaled to the actual size and type of customer generation facility installed will be used

Parties Positions on COSS

- NVE:
  - New load profiles, POP, LOLP, billing determinants for NEM
  - Didn't do a complete COSS, only added NEM customer classes and left remaining customer classes status quo
- Bombard:
  - Cost shifting, if any, can be handled through TOU (didn't realize that TOU cannot be mandatory for Residential customer classes).
- SEIA:
  - No testimony on COSS
  - COSS should include benefits
- SNHBA:
  - COSS should include benefits
  - COSS should make a distinction between retro-fit NEM and new build customers
- Staff:
  - Reject modifications to COSS – use previously approved COSS
  - Load shapes appeared to be reasonable, but use in next GRC
- TASC:
  - Reject COSS, do not create a separate customer class for NEM, and reject load shapes.
- Vote Solar:
  - Reject COSS, load shapes
  - COSS should include benefits.
  - Make modifications to calculations and inputs and file the COSS in next GRC
- BCP:
  - Distribution facilities costs are unreasonable
  - Questioned Load shape analysis
  - Solar rates should be done in next GRC with that COSS

Thank You.

For more information:

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