ATTACHMENT A

Introduction

In Decision No. C16-0127 (issued on February 16, 2016), Public Service Company of Colorado ("Public Service" or the "Company") was directed to file technical assumptions for the Commission to "consider in evaluating the RES compliance plan filed no later than February 29, 2016." In order to respond to this request, the Company has compiled this summary of modeling assumptions based on those provided in Attachment 2.8-1 in Volume II of the 2011 Electric Resource Plan ("ERP") and then updated in April of 2013 as part of the 2013 All-Source Solicitation. Accordingly, the assumptions used in the 2017 Renewable Energy Plan ("RE Plan") analysis and to be used in the 2016 ERP (to be filed no later than June 1, 2016) are included herein.

While the Company does not anticipate any major changes in assumptions between the filing of the 2017 RE Plan and the filing of the 2016 ERP, there are some discrete and specific items relevant to the ERP for which studies are still ongoing and results not yet available.[1] As a result, the following items are anticipated to be updated with newer information and/or supporting study reports filed with the 2016 ERP or in other appropriate dockets:

- Solar Integration Costs
- Coal Cycling Costs
- Flex Reserve Adequacy
- Firm Fuel Charges
- Wind and Solar Effective Load Carrying Capacity ("ELCC") (Company will file study reports supporting values presented in this report)

Because no major technical inputs and assumptions (including fuel and market prices, and load forecasts) will be updated between the 2017 RE Plan filing and the 2016 ERP filing, the Company does not anticipate any material changes to the current RES/No RES modeling as a result of these updates.

[1] In its January 26, 2016 Motion for Waiver and Variance from Decision No. C15-0925, the Company indicated that a requested three-month delay of the ERP would allow for more detailed analyses of the potential physical and economic impacts of the addition of up to 1 gigawatt of new renewable generation.

Colorado PUC E-Filings System

1. Capital Structure and Discount Rate

The rates shown in Table 1 are used to calculate the capital revenue requirements of generic resources. The after tax weighted average cost of capital ("WACC") of 6.78% is also used as the discount rate to determine the present value of revenue requirements.

Table 1 – Capital Structure

Public Service			**Decision No. C15-0292**	
Component	Capital Structure	Allowed Return	Before Tax WACC	After Tax WACC
L-T Debt	44.00%	4.67%	2.05%	1.27%
Common Equity	56.00%	9.83%	5.50%	5.50%
Total	**100%**		**7.55%**	**6.78%**
Income Tax rate	38.01%			

2. Gas Price Forecasts

Henry Hub natural gas prices are developed using a blend of the latest market information (New York Mercantile Exchange ("NYMEX") futures prices) and long-term fundamentally-based forecasts from Wood Mackenzie, Cambridge Energy Research Associates ("CERA") and Petroleum Industry Research Associates ("PIRA"). The four sources are combined to develop the composite forecast. Data from the various sources may not extend through the end of the modeling period. As the source data ends, the latest value is escalated at a GDP/inflation proxy rate to extend the forecast through the end of the modeling period.

For the basis differentials to Henry Hub of the various regional gas hubs needed for the analysis, the settlement price for the ICE-traded basis swap for the relevant hub is used. The last reported year's profile is extended through the modeling period.

While the forecasts themselves are proprietary, information regarding the three forecasting services can be found on their respective websites:

- PIRA: www.pira.com
- CERA: www.cera.com
- Wood Mackenzie: www.woodmacresearch.com

The annual average base gas price and relevant sensitivities are summarized in Table 6. Gas price sensitivities will be run in Phase I of the 2016 ERP. High and low gas price sensitivities adjust the growth rate up and down by 50 percent from the base gas price starting in year 2018. The flat gas sensitivity assumes a 2 percent per year change in gas price starting in year 2018.

3. Gas Transportation Costs

A balancing fee of $0.0532 per MMBtu will be added to all generation resources not directly connected to the Colorado Interstate Gas High Plains Pipeline system.

4. Firm Fuel Charges

In the current 2017 RE Plan modeling, the Company applied a charge of $6.16/kW-yr to generic gas fired resources to represent an estimate of the fixed costs associated with acquiring firm fuel supply to these generators either through firm gas supply or fuel oil backup infrastructure. The Company is currently examining this assumption and may provide an updated value in its 2016 ERP Phase I filing.

5. Market Prices

In addition to resources that exist within Colorado, the Company has access to markets located outside its service territory. External markets include Craig, Four Corners and the Southwest Power Pool (through the Lamar tie).

Market power prices are developed using a blend of market information from the NYMEX and fundamentally-based forecasts from Wood Mackenzie, CERA and PIRA. Regional prices relevant to Public Service are not generally available publicly; therefore, regional prices used for modeling are based on Palo Verde forward prices, where publicly available price information exists, multiplied by a scalar regional price differentials developed using 1) 2 year historical linear regression model between Palo Verde and the regional hub and 2) fundamentally based forecasts where available. Prices at Palo Verde are based on the average of the implied heat rates from the Wood Mackenzie, CERA and PIRA forecasts multiplied by the natural gas Four-Source blend. If data from the various sources does not extend through the end of the modeling period, data is extrapolated as needed. As the source data ends, implied heat rates from the last year of each forecast are carried forward through the end of the modeling period.

Detailed information regarding the three forecasting services can be found on their respective websites, however the above mentioned forecasts are available only via paid subscription:

- PIRA: www.pira.com
- CERA: www.cera.com
- Wood Mackenzie: www.woodmacresearch.com

Annual average values for the Four Corners Market are summarized in Table 6 at the end of this report.

6. Gas Price Volatility Mitigation ("GPVM") Adder

A GPVM Adder is added to the base natural gas forecast to account for potential volatility in the future price of natural gas for use in evaluating the total cost of a

natural gas-fired generating facility. The Company is using $0.61/MMBtu which is the recent cost of an "at the money" NYMEX call option covering the 10 year period starting in 2016 as the proxy for a GPVM Adder. The utilization of the GPVM will be further discussed in Phase I of the 2016 ERP.

7. Coal Price Forecasts

Coal price forecasts are developed using two major inputs: the current coal contract volumes and prices combined with current estimates of required spot market coal volumes and prices. Typically coal volumes and prices are under contract on a plant by plant basis for a one to five year term with annual spot volumes filling the estimated fuel requirements of the coal plant based on recent unit dispatch. The spot coal price forecasts are developed by averaging price forecasts provided by Wood Mackenzie, JD Energy, and John T Boyd Company, as well as price points from recent RFP responses for coal supply. Layered on top of the coal prices are transportation charges, SO_2 costs, freeze control and dust suppressant, as required.

The simple average annual coal price forecast is summarized in Table 6.

8. Reserve Margin

As in the 2011 ERP, the Company will utilize the existing Planning Reserve Margin of 16.3% applied to the 50th Percentile demand forecast based on the Loss of Load Probability (LOLP) study completed by Ventyx and filed with the Commission in 2008.

9. Surplus Capacity Credit

For the period up to the year in which the Company's loads and resources table shows firm generation capacity in excess of the planning reserve margin (i.e. the periods in which the Company is currently long capacity), surplus capacity will be credited $2.79/kW-mo up to an excess of 200 MW in the Phase I alternative plan analysis and during Phase II portfolio creation. The surplus capacity credit price is based on bids received by Southwestern Public Service for seasonal capacity for the 2011 summer season. This credit will be applied for the four summer months of June through September. After this period, surplus capacity credit for up to 500 MW will be priced at the cost of a generic combustion turbine for all twelve months of a year. The utilization of a Surplus Capacity Credit will be further discussed in Phase I of the 2016 ERP.

10. Seasonal Capacity Purchases

The Company does not currently anticipate that Seasonal Capacity Purchases will play a part in the Phase I alternative plan analysis.

11. CO_2 Price Forecasts

Base modeling assumptions are a $0/ton CO_2 proxy price. Consistent with Decision No. C13-1566 in Proceeding No. 11A-869E (consolidated), the

utilization of a CO_2 sensitivity case(s) will be further discussed in Phase I of the 2016 ERP.

12. Inflation / Construction Escalation Rates

The inflation rate used for construction (capital) costs, non-fuel variable O&M, fixed O&M and any other escalation factor related to general inflationary trends is the long-term forecast from Global Insight for the "Chained Price Index for Total Personal Consumption Expenditures" published in the third quarter of 2015. This rate is 2.0% and will be applied throughout the entire planning period as a base assumption.

13. Demand Side Management Forecasts

As directed by the Commission, the DSM goals approved in the 2013 Strategic Issues docket (Decision No. C14-0731) will be used in determination of the resource need in Phase I of the 2016 ERP.

The approved Demand Reduction goals have two components:

1) An annual 65 MW target of Demand Reduction to be achieved through the Company's Energy Efficiency programs within the Company's DSM portfolio for 2015-2020, and
2) A remaining level of dispatchable Demand Reduction to be achieved through the Company's Demand Response programs (such as Saver's Switch and ISOC) for 2015-2020.

The 65 MW of required annual Energy Efficiency reductions are accounted for in the Company's load forecast. The remaining Demand Reduction levels (to be achieved through growth in the Company's dispatchable Demand Response programs) are subtracted directly from the Company's forecasted Obligation Load to determine resource need. A summary of the ordered Demand Reduction target levels that will be used to determine the 2016 ERP Phase I resource need is summarized in Table 2:

Table 2: Demand Reduction Goals

	2016	2017	2018	2019	2020	2021	2022	2023	2024	2025
Dispatchable DR Goal (MW)	537	555	575	598	623	623	623	623	623	623

Since the specified goals currently only extend through 2020, the current assumption is that dispatchable Demand Response levels remain flat after 2020 for purposes of resource need determination.

14. Transmission Delivery Costs

Estimates of transmission delivery costs of the generic resources will be included in the cost estimates in Phase I of the 2016 ERP. In any Phase II of the 2016 ERP, the Company will allocate or assign transmission delivery costs on a pro-rata share of transmission upgrades needed for each individual Phase II bid. The Company will not assign transmission delivery costs to projects that will

utilize existing transmission capacity or that will utilize transmission projects for which the Company has been granted a Certificate of Public Convenience and Necessity at the time of the bid evaluation.

15. Transmission Interconnection Costs

Estimates of transmission interconnection costs of the generic resources will be included in the cost estimates in Phase I of the 2016 ERP.

16. ELCC Capacity Credit for Wind Resources

The ELCC of the Company's existing wind portfolio is assigned a rate of 16.0% based on the Company's most recent wind ELCC study. Incremental wind is assigned an ELCC rate dependent upon the level of the incremental wind (MW) and the location of the wind based on Table 3 below. Table 3 values are based on the Company's most recent wind ELCC study.

Table 3: Average ELCC to Apply to Incremental Wind

Incremental Wind (MW_AC)	Northern	Limon	Lamar
250	10.0%	9.8%	18.8%
500	9.7%	9.2%	16.9%
1000	9.1%	8.4%	14.0%

The Company will file its most recent wind ELCC study report at the time it files the 2016 ERP.

17. ELCC Capacity Credit for Solar Resources

The ELCC of the Company's existing utility-scale solar portfolio is assigned a rate of 55.0% (MW_AC basis) and the ELCC of the Company's existing distribution-interconnected solar portfolio is assigned a rate of 37.0% (MW_AC basis) based on the Company's most recent solar ELCC study. Incremental solar is assigned an ELCC rate dependent upon the level of the incremental solar generation (MW_AC), the location of the solar generation, and whether the generation can track or is mounted fixed based on Table 4 below. Table 4 values are based on the Company's most recent solar ELCC study.

Table 4: Average ELCC to Apply to Incremental Solar

Incremental Solar (MW_AC)	Northern Front Range		San Luis Valley		Western Slope	
	Fixed	Tracking	Fixed	Tracking	Fixed	Tracking
50	37.0%					
100	37.0%	41.5%	43.5%	52.5%	41.5%	53.0%
250	35.8%	40.2%	42.2%	50.4%	41.0%	52.0%
500	33.9%	37.8%	39.1%	47.1%	39.0%	49.5%
1000	30.3%	33.2%				
1500	27.7%	29.1%				

The Company will file its most recent solar ELCC study report at the time it files the 2016 ERP.

18. Resource Acquisition Period

Resource Acquisition Period ("RAP") means the first six to ten years of the Planning Period, in which the utility acquires specific resources to meet projected electric system demand and energy requirements. The RAP begins on the date the utility files its ERP with the Commission. For the 2016 ERP, the RAP can cover a minimum period of June 1, 2016 – June 1, 2022 and a maximum period of June 1, 2016 – June 1, 2026. The Company will propose a RAP during Phase I of the 2016 ERP.

For the 2017 RE Plan filing, the Company proposes programs to acquire additional resources for calendar years 2017-2019.

19. Planning Period

Planning Period means the future period for which a utility develops its ERP and the period over which net present value of revenue requirements for resources are calculated. Pursuant to Rule 3602(k), the planning period is 20 to 40 years and begins from the date the utility files its plan with the Commission. The planning period is from June 1, 2016 – June 1, 2054.

20. SO_2 Effluent Costs and Allocations

SO_2 is controlled through the Acid Rain program in Colorado. Through this program, the Company has excess SO_2 allowances because of the use of low sulfur coal and scrubber retrofits at the Arapahoe, Cherokee, Hayden, and Valmont units. Therefore, the Company does not anticipate that it will have to purchase any allowances for SO_2 under current or reasonably foreseeable legislation. In addition, Acid Rain allowances are trading for less than $1.00 per ton so the value of the excess allowances that the Company owns is very little. Therefore, the Company assigns no effluent costs or allocations to SO_2. SO_2 effluent costs (as measured in $/ton) will remain zero unless a major change in legislation occurs during the deliberation of the ERP.

21. NO_x Effluent Costs and Allocations

There is no trading program for sources of NO_x in Colorado; therefore, no cost is applied to NO_x emissions. The primary programs that reduce NO_x are the Regional Haze Rule through the application of the Best Available Retrofit Technology program, which seeks to achieve further reasonable progress towards long term visibility goals in Class I areas like national parks and wilderness areas. The Denver ozone State Implementation Plan ("SIP") is also another driver for NO_x reductions. As a result, the costs of NO_x reductions are embedded in capital and operating costs of the resources included in the SIP (e.g., the Selective Catalytic Reduction additions to Pawnee and Hayden). NO_x effluent costs (as measured in $/ton) will remain zero unless a major change in legislation occurs during the deliberation of the ERP.

22. Mercury Effluent Costs and Allocations

Mercury is also controlled as a command and control rule through the Colorado Mercury Rule. Therefore, there is no cap and trade for mercury either and effluent costs and allocations will be assigned a zero cost in the Phase I alternative plan analysis. As with SO_2 and NO_x, costs associated with controlling these emissions were captured in the resource costs. Mercury effluent costs (as measured in $/ton) will remain zero unless a major change in legislation occurs during the deliberation of the ERP.

23. Spinning Reserve Requirement

Spinning Reserve is the on-line reserve capacity that is synchronized to the grid to maintain system frequency stability during contingency events and unforeseen load swings. The level of spinning reserve modeled was consistent with the Company's Rocky Mountain Reserve Group ("RMRG") requirements. The cost of spinning reserve was estimated in the Strategist model by assigning a spin requirement and the spinning capability of each resource.

The spinning reserve requirement is modeled as 210 MW consistent with the newest value from RMRG.

24. Emergency Energy Costs

Emergency Energy Costs were assigned in the Strategist model if there were not enough resources available to meet energy requirements. The cost was set at an arbitrary cost ($500/MWh) which is far above the cost of the most expensive resource. Emergency energy costs occur only in rare instances.

25. Dump Energy / Wind Curtailment Costs

When wind energy is curtailed within the Strategist model in order to maintain the balance between load and generation, the Company accounts for the potential lost Production Tax Credit ("PTC") value. These potential costs are captured by multiplying the levels of the "dump energy" variable in the model (which is assumed to be curtailed wind generation) times the grossed-up value of the PTC (PTC/(1-tax rate)).

26. Wind Integration Costs

Wind integration costs are priced based upon the results of the *2 GW and 3 GW Wind Integration Cost Study* completed in August 2011 (see Attachment 2.13-1 in the Company's 2011 ERP filing).

Table 7 (included at the end of these assumptions) shows the wind integration costs that would be assigned to a 500 MW wind project based on the Base Gas Price Forecast shown in Table 6.

27. Wind Induced Coal Plant Cycling Costs

For the 2017 RE Plan, wind-induced coal cycling costs were priced as described in *Wind Induced Coal Plant Cycling Costs and the Implications of Wind Curtailment* study completed in August 2011 and updated in April 2013 (see Attachment 2.12-1 in the Company's 2011 ERP filing). The study addressed both coal plant cycling costs and wind curtailment costs. Wind curtailment costs are estimated within the Strategist model (see Assumption #25) and therefore this component of cycling costs from the study was not included in the Strategist modeling. Table 7 shows the wind induced coal cycling costs that are utilized in the 2017 RE Plan modeling.

The Company intends to file with the Commission in Phase I of the 2016 ERP its most recent coal plant cycling study, which evaluates higher penetrations of wind and solar generation. The results of this study will be used in the 2016 ERP Phase I modeling and Phase II bid evaluation.

28. Solar Integration Costs

For the 2017 RE Plan, solar integration costs were priced upon the results of the *Solar Integration Study* completed in February 2009; see Attachment JFH-4 filed in Proceeding No. 16A-0055E. Table 7 shows the resulting solar integration costs assigned to solar in the 2017 RE Plan.

The Company intends to file with the Commission in Phase I of the 2016 ERP its most recent solar integration cost study report which evaluates: 1) higher penetrations of solar generation, and 2) lower gas costs than assumed in the 2009 study. The results of that study will be used in the 2016 ERP Phase I modeling and Phase II bid evaluation.

29. Owned Unit Modeled Operating Characteristics and Costs

Company-owned units were modeled based upon their tested operating characteristics and historical or projected costs. Below is a list of operating and cost inputs for each company-owned resource:

a. Maximum Capacity
b. Minimum Capacity Rating
c. Seasonal Deration

d. Heat Rate Profiles
e. Variable O&M
f. Fixed O&M
g. Maintenance Schedule
h. Forced Outage Rate
i. Emission rates for SO_2, NO_x, CO_2, Mercury and PM
j. Contribution to spinning reserve
k. Fuel prices
l. Fuel delivery charges

30. Thermal PPA Operating Characteristics and Costs

Power Purchase Agreements ("PPA") are modeled based upon their tested operating characteristics and contracted costs. Below is a list of operating and cost inputs for each thermal purchase power contract:

a. Contract term
b. Maximum Capacity
c. Minimum Capacity Rating
d. Seasonal Deration
e. Heat Rate Profiles
f. Energy Schedule
g. Capacity Payments
h. Energy Payments
i. Maintenance Schedule
j. Forced Outage Rate
k. Emission rates for SO_2, NO_x, CO_2, Mercury and PM
l. Contribution to spinning reserve
m. Fuel prices
n. Fuel delivery charges

31. Renewable Energy PPA Operating Characteristics and Costs

PPAs are modeled based upon their tested operating characteristics and contracted costs. Below is a list of operating and cost inputs for each renewable energy purchase power contract:

a. Contract term
b. Name Plate Capacity
c. Accredited Capacity
d. Annual Energy
e. Hourly Patterns
f. Capacity Payments
g. Energy Payments
h. Integration Costs
i. Emission rates for SO_2, NO_x, CO_2, Mercury and PM if applicable

Integration and cycling costs will be updated as addressed elsewhere in this document.

32. Load Forecast

The same load forecast that was used in the 2017 RE Plan modeling will be used in the Company's 2016 ERP Phase I analyses. Table 5 below represents the Company's currently projected resource need based on the current load forecast (as presented in Table 7), a continuation past 2019 of the customer-choice solar additions proposed in the 2017 RE Plan filing for years 2017-2019, and the proposed levels of Solar*Connect solar additions set forth in the January 2016 filing.

Table 5 – PSCo Resource Need Forecast

	2016	2017	2018	2019	2020	2021	2022	2023	2024	2025
Need (MW)	0	0	0	0	0	30	325	655	832	870

Forecast Tables

Table 6: Fuel and Market Price Inputs

	CIG Rocky Mountain Gas Price Forecast ($/mmBtu)				4-Corners Electric Market Price Forecast ($/MWh)		Coal Price Forecast ($/mmBtu)
	Low	Base	High	Flat	On-Peak	Off-Peak	Base
2016	2.13	2.13	2.13	2.13	23.35	18.68	1.68
2017	2.46	2.46	2.46	2.46	26.80	22.79	1.73
2018	2.53	2.61	2.68	2.51	28.22	23.22	1.75
2019	2.64	2.83	3.02	2.56	30.81	24.27	1.80
2020	2.94	3.46	4.04	2.61	35.73	27.91	1.79
2021	3.12	3.88	4.77	2.67	36.49	28.48	1.84
2022	3.18	4.05	5.08	2.72	36.98	29.04	1.88
2023	3.26	4.24	5.44	2.77	37.46	29.57	1.92
2024	3.31	4.37	5.69	2.83	39.68	31.63	1.97
2025	3.37	4.53	6.00	2.89	41.21	33.33	2.01
2026	3.43	4.68	6.30	2.94	43.19	37.08	2.04
2027	3.51	4.91	6.76	3.00	44.72	38.52	2.08
2028	3.60	5.17	7.29	3.06	46.60	40.39	2.11
2029	3.68	5.40	7.78	3.12	48.75	42.53	2.16
2030	3.73	5.54	8.09	3.19	49.60	43.78	2.20
2031	3.82	5.81	8.69	3.25	52.11	45.99	2.25
2032	3.90	6.06	9.24	3.32	54.27	47.93	2.30
2033	3.96	6.25	9.67	3.38	55.88	49.40	2.35
2034	4.02	6.42	10.06	3.45	57.32	50.73	2.41
2035	4.07	6.58	10.44	3.52	58.59	52.11	2.47
2036	4.11	6.71	10.75	3.59	59.74	53.14	2.52
2037	4.15	6.84	11.08	3.66	60.92	54.19	2.58
2038	4.19	6.98	11.41	3.73	62.13	55.26	2.63
2039	4.23	7.12	11.75	3.81	63.35	56.35	2.70
2040	4.28	7.26	12.10	3.89	64.61	57.47	2.76
2041	4.32	7.41	12.47	3.96	65.88	58.60	2.83
2042	4.36	7.56	12.84	4.04	67.18	59.76	2.89
2043	4.41	7.71	13.23	4.12	68.51	60.94	2.96
2044	4.45	7.86	13.62	4.21	69.86	62.14	3.03
2045	4.49	8.02	14.03	4.29	71.24	63.37	3.11
2046	4.54	8.18	14.45	4.38	72.65	64.62	3.18
2047	4.58	8.34	14.89	4.46	74.08	65.90	3.25
2048	4.63	8.51	15.33	4.55	75.55	67.20	3.32
2049	4.68	8.68	15.79	4.64	77.04	68.52	3.39
2050	4.72	8.85	16.27	4.74	78.56	69.88	3.46
2051	4.77	9.03	16.75	4.83	80.11	71.26	3.53
2052	4.82	9.21	17.25	4.93	81.69	72.67	3.60
2053	4.87	9.39	17.77	5.03	83.31	74.10	3.67
2054	4.91	9.58	18.30	5.13	84.95	75.56	3.74

Table 7: Wind and Solar Integration Costs, Load Forecast

	Wind Integration Cost ($/MWh)	Wind-Induced Coal Cycling Cost ($/MWh)	Solar Integration Cost ($/MWh)		Load Forecast	
	Additional 500MW	Incremental Wind	All Solar		Peak (MW)	Energy (GWh)
2016	1.18	1.01	0.00		6,620	33,756
2017	1.70	1.08	0.00		6,712	34,283
2018	1.77	1.10	0.00		6,768	34,628
2019	1.85	1.09	0.00		6,884	35,141
2020	1.93	1.15	0.00		6,970	35,889
2021	2.01	1.09	0.00		7,102	36,754
2022	2.09	1.18	0.02		7,161	37,116
2023	2.17	1.19	0.20		7,225	37,484
2024	2.26	1.24	0.31		7,299	37,878
2025	2.34	1.18	0.46		7,352	38,190
2026	2.43	1.18	0.59		7,413	38,537
2027	2.52	1.18	0.80		7,479	38,915
2028	2.62	1.18	1.03		7,557	39,312
2029	2.71	1.18	1.24		7,615	39,742
2030	2.81	1.18	1.38		7,680	40,130
2031	2.90	1.18	1.62		7,738	40,496
2032	3.00	1.18	1.85		7,802	40,859
2033	3.10	1.18	2.02		7,850	41,214
2034	3.21	1.18	2.17		7,902	41,579
2035	3.31	1.18	2.32		7,962	41,957
2036	3.42	1.18	2.43		8,045	42,340
2037	3.53	1.18	2.56		8,098	42,677
2038	3.64	1.18	2.68		8,163	43,016
2039	3.76	1.18	2.81		8,225	43,367
2040	3.88	1.18	2.94		8,299	43,717
2041	3.99	1.18	3.07		8,352	44,053
2042	4.12	1.18	3.20		8,416	44,400
2043	4.24	1.18	3.34		8,481	44,743
2044	4.37	1.18	3.48		8,554	45,126
2045	4.50	1.18	3.62		8,613	45,528
2046	4.63	1.18	3.77		8,670	45,873
2047	4.76	1.18	3.92		8,717	46,218
2048	4.90	1.18	4.07		8,761	46,667
2049	5.04	1.18	4.22		8,802	47,029
2050	5.18	1.18	4.38		8,841	47,377
2051	5.33	1.18	4.54		8,877	47,724
2052	5.47	1.18	4.70		8,911	48,181
2053	5.63	1.18	4.87		8,941	48,516
2054	5.78	1.18	5.04		8,970	48,836