Puget Sound Power & Light Company

Docket No: UE-920499
WICFUR Data Requests

Request 310:

With reference to Exhibit No. DWH-1, page 8, lines 20-21, please provide a complete copy of the avoided cost study.

Response:

Please see attached study.

#11

Puget Sound Power & Light Company
Documentation for 1991 Long-Term Firm Avoided Cost Forecast

Introduction

Puget Power will be issuing a new RFP for conservation and generation resource in 1991. As part of the information required for that solicitation, Puget has developed the following avoided cost schedule which is intended to be the maximum price for acquisitions. This forecast was developed based upon the definition of "Avoided Costs" set forth in WAC 480-107-005 and therefore does not include conservation or non-utility purchases.

Puget intends to include externalities by applying the 10% credit from the regional act to conservation proposals and to carry this further by extending the 10% credit to renewable generating resources also. Consequently, since externalities will be taken into account by this credit to the bid price, the avoided cost forecast does not include and adjustments for externalities.

Load and Resource Situation

Puget's current load and resource situation is a primary input to the avoided cost forecast. As shown below in table 1, Puget has a significant need for additional firm power in 1991-1992 and from 1996 on. For the three year period, from 1993-1995, Puget is very close to load/resource balance and additional firm resources are not needed.

Table 1
Firm Loads and Resources
(Energy - aMW)

Year	Load	Resources	Surplus/ Deficit
1991	2254	2087	-168
1992	2317	2159	-159
1993	2381	2358	-24
1994	2441	2472	31
1995	2493	2469	-25
1996	2541	2428	-114
1997	2592	2365	-227
1998	2643	2330	-313
1999	2692	2305	-387
2000	2743	2285	-458

The resource column above contains the energy acquired through our pilot competitive bid (RFP issued in June 1989) and two follow-up cogeneration contracts.

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Puget's load and resource situation has gone through many evolutions since the pilot competitive bid was initiated in June 1989. The pilot competitive bid solicitation sought approximately 100 aMW of new energy resource in mid-1993. Since it was a pilot process to test competitive bidding, the target resource block was less than our forecast requirement. Puget expected to meet part of that shortfall through purchases from other utilities. However, for various reasons none of these prospective purchases were completed.

In early 1990, Puget's pilot competitive bid process was completed resulting in the selection of five conservation and three generation projects representing 137 aMW of energy. About this same time, Puget produced a new load forecast taking into account more current information about the local economy. The new load forecast was higher than the old forecast to such a degree as to almost completely offset the 137 aMW of energy obtained through the competitive bid.

To help meet some of the increased need, Puget elected to exercise an option to take 130 aMW from the Enserch Cogenerator instead of the 100 aMW option originally reported. This increased the amount from the competitive bid award group to 167 aMW.

Even with the additional competitive bid energy, Puget forecast large firm energy deficits beginning in 1993-94. Since we already had a extensive pool of bid proposals that weren't selected, Puget decided to continue discussion with these bidders regarding possible power purchase in a follow-up to the formal bid process. However, since their initial bids were not selected, Puget took the position that proposals needed to be improved to the level of the preliminary award group before any discussions could progress.

Also during this time, Puget was receiving unsolicited proposals from new developers wanting to sell power. In order to better compare projects, Puget met with the each developer and asked them a set of questions intended to gather information very similar to that required during the formal process.

The new proposals and the improved bid proposals were evaluated and compared to determine the maturity and quality of each project. As a result, two projects were selected for acquisition. These two proposals, by March Point Cogeneration and by a partnership of Tenaska Inc. and Continental Energy Inc., compare favorably with the winners of the initial competitive bid solicitation.

Most recently, a new load forecast was completed that reflects an expected short-term slowdown in the general economy (see Table 1). The firm energy requirement in the early 1990s drops by about 40 aMW from the previous forecast.

Avoided Cost Forecast

Puget Power's least cost planning process produces a wide range of resource plans developed to meet the load for a number of future scenarios. No single resource path is designated as the best alternative. Rather, the action plan chooses alternatives that limit risk and work over a range of futures.

The avoided cost forecast is developed using the results of the least cost plan. However, the forecast requires a single set of numbers rather than a range. Developers need to know that in 1994 they will be paid 42 mills rather than between somewhere between 30 and 50 mills. Therefore, the alternate resource plans developed in the least cost planning process are reduced to a single set of resources that is used for the avoided costs.

The avoided cost forecast described herein was developed using three distinct time periods based upon Puget resource requirements, and the availability and cost of generating resource alternatives. During the first time period, extending from 1991 to 1992, Puget has a need for firm supply and new utility projects are not available because of construction lead-times. The forecast for period 1 is based upon an short-term utility firm purchase. A forecast of the BPA NR rate was used as a proxy for the price of such a purchase although BPA will not necessarily be the supplier.

The second period lasts from 1993 until 1995. During this time, Puget is very close to load and resource balance and does not need additional firm resources. Therefore, the avoided cost for period 2 is based upon Puget's avoidable non-firm energy costs. The nonfirm rates were determined using Puget's power cost model to evaluate the cost of serving the top 100 aMW of load.

The third period begins in 1996 when Puget again needs additional firm resources. A new combined cycle combustion turbine was selected as the avoidable resource because of its cost compared to other long-term resource alternatives.

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I. Period 1 - BPA NR Rate

BPA last published a forecast of their New Resources Rate in the report: "Wholesale Power Rate Projections" from November 1990. The Medium Case NR rate forecast is shown in Table I-1.

Table I-1
BPA NR Rate Forecast

Year	Nominal Rate mills/KWH
1991	31.0
1992	32.1

For the avoided cost forecast, the total average annual rates listed above need to be broken into seasonal firm energy and annual capacity rates. The current NR components were used as the basis for this allocation.

First the current NR components are combined into a single annual average rate.

Current NR components:
- 25.5 mills/KWH firm energy September-March
- 21.2 mills/KWH firm energy April-August
- 4.13 $/KW-month firm capacity

Assuming flat generation at 1 aMW and 100% load factor, the annual average is calculated as follows:

$$\frac{25.5 * 5{,}088 \text{ MWH} + 21.2 * 3{,}672 \text{ MWH} + 4.13 * 12{,}000}{8{,}760 \text{ MWH}} = 29.4$$

Next the contribution of each component to the average is calculated:

Winter firm energy $\frac{25.5 * 5{,}088}{29.4 * 8{,}760} = 50.45\%$

Summer firm energy $\frac{21.2 * 3{,}672}{29.4 * 8{,}760} = 30.27\%$

Capacity $\frac{4.13 * 12{,}000}{29.4 * 8{,}760} = 19.28\%$

Using the derived percentage contribution of each component, the nominal rates forecast by BPA can be broken into components.

Sample calculation of seasonal energy and annual capacity avoided cost components:

1991 total rate - 31 mills

Winter firm energy $$\frac{31.0 * 8,760 * 0.5045}{5,088} = 26.93$$

Summer firm energy $$\frac{31.0 * 8,760 * 0.3027}{3,672} = 22.39$$

Capacity $$\frac{31.0 * 8,760 * 0.1928}{12,000} = 4.36$$

The 1992 components can be similarly determined. The final avoided cost forecast for period 1 is below in table I-2.

Table I-2
BPA NR Rate
Period 1 Avoided Costs by Components

Year	Winter Firm Energy Rate mills/KWH	Summer Firm Energy Rate mills/KWH	Firm Capacity Rate $/KW-month
1991	26.93	22.39	4.36
1992	27.88	23.18	4.52

II. Period 2 - Nonfirm Energy Rates

The firm energy avoided costs for period 2 and the nonfirm energy avoided costs for the entire forecast are based upon the decremental cost of meeting the top 100 aMW of load using the Puget Power Production Costing Model. Typical avoidable costs for resources used to meet the top 100 aMW include thermal plant fuel and variable O&M, secondary transactions with other utilities, and the variable costs of certain contracts. Since additional firm capacity is not needed for period 2, the firm capacity avoided cost is zero.

Table II-1
Nonfirm Energy-Only Rates
Avoided Costs by Components

Year	Winter NonFirm Component mills/KWH	Summer NonFirm Component mills/KWH
1991	22.16	19.01
1992	22.95	20.20
1993*	23.36	21.14

Table II-1 (continued)
Nonfirm Energy-Only Rates
Avoided Costs by Components

Year	Winter NonFirm Component mills/KWH	Summer NonFirm Component mills/KWH
1994*	25.09	23.01
1995*	26.51	23.84
1996	28.05	25.19
1997	29.99	26.02
1998	31.20	26.71
1999	32.90	28.26
2000	34.16	29.67
2001	36.61	31.47
2002	42.26	32.57
2003	46.20	34.36
2004	49.66	36.19
2005	51.31	37.68
2006	54.94	39.55
2007	58.82	41.53
2008	61.76	43.60
2009	64.85	45.78
2010	68.09	48.07
2011	71.50	50.47
2012	75.07	53.00
2013	78.83	55.65
2014	82.77	58.43
2015	86.91	61.35
2016	91.25	64.42
2017	95.82	67.64
2018	100.61	71.02
2019	105.64	74.57
2020	110.92	78.30
2021	116.46	82.22
2022	122.29	86.33
2023	128.40	90.65
2024	134.82	95.18
2025	141.56	99.94
2026	148.64	104.93
2027	156.07	110.18
2028	163.88	115.69
2029	172.07	121.47
2030	180.68	127.54

* Nonfirm forecast is the firm forecast for these years.

III. Period 3 - Combined Cycle Combustion Turbine

Puget's avoided cost forecast for 1996 forward is based upon the cost of a new combined cycle combustion turbine. Listed in Table III-1 are the pertinent cost data.

Table III-1
Combined Cycle Combustion Turbine
Costs in 1991 $

Capital Cost (incl. AFUDC)	615	$/KW
Fixed O&M	0.8	mills
Variable O&M	3.2	mills
Heat Rate	7,740	BTU/KWH
Annual Availability	75%	
Fuel Cost	2.6	$/MMBTU

The combined cycle combustion turbine fixed and variable O&M were assumed to escalate at general inflation as shown in Table III-2.

Table III-2
Combined Cycle Combustion Turbine
Operation and Maintenance Costs
(mills/KWH)

Year	Inflation	O&M
1991	3.7%	4.00
1992	3.7%	4.15
1993	3.1%	4.28
1994	3.1%	4.41
1995	3.7%	4.57
1996	3.9%	4.75
1997	4.0%	4.94
1998	4.1%	5.14
1999	4.1%	5.35
2000	4.4%	5.58
2001	4.8%	5.85
2002	5.0%	6.14
2003	4.9%	6.44
2004	4.9%	6.76
2005	4.9%	7.09
2006	4.9%	7.44
2007	5.0%	7.81
2008	5.1%	8.21
2009	5.1%	8.63
2010	5.1%	9.07
2011	5.1%	9.53
2012	5.1%	10.02

Table III-2 (continued)
Combined Cycle Combustion Turbine
Operation and Maintenance Costs
(mills/KWH)

Year	Inflation	O&M
2013	5.1%	10.53
2014	5.2%	11.08
2015	5.2%	11.65
2016	5.0%	12.23
2017	5.0%	12.85
2018	5.0%	13.49
2019	5.0%	14.16
2020	5.0%	14.87
2021	5.0%	15.61
2022	5.0%	16.39
2023	5.0%	17.21
2024	5.0%	18.07
2025	5.0%	18.98
2026	5.0%	19.93
2027	5.0%	20.92
2028	5.0%	21.97
2029	5.0%	23.07
2030	5.0%	24.22

* Inflation: 1991-2000 from Data Resources Inc., Review of the U.S. Economy, Ten-year Projections, October 1990; 2001-2015 from Data Resources Inc., Review of the U.S. Economy, Long-Range Focus, Summer 1990; 2016-2030 set to 5%.

Natural gas prices were forecast by applying a recent national natural gas forecast to the current market price.

Natural Gas Price Calculation:

Gas price delivered	2.6 $/MMBTU
Heat rate	7.74 MMBTU/MWH

2.6 $/MMBTU * 7.74 BTU/MWH = 20.12 $/MWH

Table III-3
Combined Cycle Combustion Turbine
Fuel Costs
(mills/KWH)

Year	Natural Gas Price Escalation	Fuel Cost
1991	6.0%	20.12
1992	4.6%	21.05
1993	4.6%	22.02

Table III-3 (continued)
Combined Cycle Combustion Turbine
Fuel Costs
(mills/KWH)

Year	Natural Gas Price Escalation	Fuel Cost
1994	17.4%	25.86
1995	17.4%	30.38
1996	9.3%	33.21
1997	9.3%	36.31
1998	9.3%	39.70
1999	9.3%	43.41
2000	9.3%	47.46
2001	4.8%	49.74
2002	5.0%	52.23
2003	4.9%	54.79
2004	4.9%	57.47
2005	4.9%	60.29
2006	4.9%	63.24
2007	5.0%	66.40
2008	5.1%	69.79
2009	5.1%	73.35
2010	5.1%	77.09
2011	5.1%	81.02
2012	5.1%	85.15
2013	5.1%	89.50
2014	5.2%	94.15
2015	5.2%	99.05
2016	5.0%	104.00
2017	5.0%	109.20
2018	5.0%	114.66
2019	5.0%	120.39
2020	5.0%	126.41
2021	5.0%	132.73
2022	5.0%	139.37
2023	5.0%	146.34
2024	5.0%	153.65
2025	5.0%	161.34
2026	5.0%	169.41
2027	5.0%	177.88
2028	5.0%	186.77
2029	5.0%	196.11
2030	5.0%	205.92

* Escalation: 1991-2000 from NERA Energy Outlook, 12/24/90; 2001-2015 inflation from Data Resources Inc., Review of the U.S. Economy, Long-Range Focus, Summer 1990; 2016-2030 set to 5%.

The levelized capital costs for a new combined cycle combustion turbine can be calculated based upon the estimated 1991 construction cost including AFUDC of $615 per KW.

Fixed charge rate - 13.16%
On-line year - 1996

($615 * 1000 * .1316)/(8760 * 0.75) = 12.32

This levelized capital value can then be inflated to the plant's on-line year of 1996 as shown below.

Table III-4
Combined Cycle Combustion Turbine
Levelized Capital
(mills/KWH)

Year	Inflation	Capital
1991	3.7%	12.32
1992	3.7%	12.77
1993	3.1%	13.17
1994	3.1%	13.58
1995	3.7%	14.07
1996	3.9%	14.62

Combining all the cost components yields the total generic combined cycle combustion turbine unit cost as shown in Table III-5

Table III-5
Combined Cycle Combustion Turbine
Total Costs
(mills/KWH)

Year	Fuel	O&M	Levelized Capital	Costs
1996	33.21	4.75	14.62	52.58
1997	36.31	4.94	14.62	55.87
1998	39.70	5.14	14.62	59.46
1999	43.41	5.35	14.62	63.38
2000	47.46	5.58	14.62	67.67
2001	49.74	5.85	14.62	70.21
2002	52.23	6.14	14.62	72.99
2003	54.79	6.44	14.62	75.85
2004	57.47	6.76	14.62	78.85
2005	60.29	7.09	14.62	82.00
2006	63.24	7.44	14.62	85.30
2007	66.40	7.81	14.62	88.83
2008	69.79	8.21	14.62	92.62
2009	73.35	8.63	14.62	96.60

Table III-5
Combined Cycle Combustion Turbine
Total Costs
(mills/KWH)

Year	Fuel	O&M	Levelized Capital	Costs
2010	77.09	9.07	14.62	100.78
2011	81.02	9.53	14.62	105.17
2012	85.15	10.02	14.62	109.79
2013	89.50	10.53	14.62	114.64
2014	94.15	11.08	14.62	119.85
2015	99.05	11.65	14.62	125.32
2016	104.00	12.23	14.62	130.85
2017	109.20	12.85	14.62	136.66
2018	114.66	13.49	14.62	142.77
2019	120.39	14.16	14.62	149.17
2020	126.41	14.87	14.62	155.90
2021	132.73	15.61	14.62	162.97
2022	139.37	16.39	14.62	170.38
2023	146.34	17.21	14.62	178.17
2024	153.65	18.07	14.62	186.35
2025	161.34	18.98	14.62	194.93
2026	169.41	19.93	14.62	203.96
2027	177.88	20.93	14.62	213.43
2028	186.77	21.97	14.62	223.36
2029	196.11	23.07	14.62	233.80
2030	205.92	24.22	14.62	244.76

The total avoided cost for the CC CT must be broken into seasonal firm energy and capacity components as was done for the BPA NR rate in period 1. Maintaining the weighting percentages from the BPA NR rate analysis yields the following avoided cost components for period 3.

Table III-6
Combined Cycle Combustion Turbine
Period 3 Avoided Costs by Components

Year	Winter Firm Energy Rate mills/KWH	Summer Firm Energy Rate mills/KWH	Firm Capacity Rate $/KW-month
1996	45.67	37.97	7.40
1997	48.53	40.34	7.86
1998	51.65	42.94	8.37
1999	55.05	45.77	8.92
2000	58.77	48.86	9.52
2001	60.99	50.70	9.88
2002	63.40	52.71	10.27
2003	65.88	54.77	10.68
2004	68.49	56.94	11.10

Table III-6
Combined Cycle Combustion Turbine
Period 3 Avoided Costs by Components

Year	Winter Firm Energy Rate mills/KWH	Summer Firm Energy Rate mills/KWH	Firm Capacity Rate $/KW-month
2005	71.22	59.21	11.54
2006	74.09	61.60	12.01
2007	77.16	64.15	12.50
2008	80.45	66.88	13.04
2009	83.90	69.76	13.60
2010	87.54	72.77	14.18
2011	91.35	75.95	14.80
2012	95.36	79.28	15.45
2013	99.58	82.79	16.14
2014	104.10	86.54	16.87
2015	108.85	90.50	17.64
2016	113.66	94.49	18.42
2017	118.71	98.69	19.23
2018	124.01	103.10	20.09
2019	129.57	107.72	21.00
2020	135.42	112.58	21.94
2021	141.55	117.68	22.94
2022	147.99	123.04	23.98
2023	154.76	128.66	25.08
2024	161.86	134.57	26.23
2025	169.32	140.77	27.44
2026	177.16	147.29	28.71
2027	185.38	154.12	30.04
2028	194.01	161.29	31.44
2029	203.08	168.83	32.91
2030	212.60	176.75	34.45

V. Variable Firm Avoided Costs

Under the prescribed methodology, Puget's avoided cost forecast is devided into fixed and variable components. The fixed avoided costs can be levelized for the purpose of establishing purchase rates. Whereas the variable firm avoided costs are not typically levelized and will escalate through time at actual inflation.

For the purposes of this forecast, the variable firm avoided cost established in the May 1989 avoided costs filing is escalated at estimated inflation.

Table V-1
Variable Firm Avoided Costs
(mills/KWH)

Year	Inflation	Rate
1989		8.00
1990	4.04%	8.32
1991	3.65%	8.63
1992	3.67%	8.94
1993	3.12%	9.22
1994	3.09%	9.51
1995	3.66%	9.86
1996	3.92%	10.24
1997	3.96%	10.65
1998	4.05%	11.08
1999	4.12%	11.54
2000	4.39%	12.04
2001	4.80%	12.62
2002	5.00%	13.25
2003	4.90%	13.90
2004	4.90%	14.58
2005	4.90%	15.30
2006	4.90%	16.04
2007	5.00%	16.85
2008	5.10%	17.71
2009	5.10%	18.61
2010	5.10%	19.56
2011	5.10%	20.56
2012	5.10%	21.60
2013	5.10%	22.71
2014	5.20%	23.89
2015	5.20%	25.13
2016	5.00%	26.39
2017	5.00%	27.70
2018	5.00%	29.09
2019	5.00%	30.54
2020	5.00%	32.07
2021	5.00%	33.68
2022	5.00%	35.36
2023	5.00%	37.13
2024	5.00%	38.98
2025	5.00%	40.93
2026	5.00%	42.98
2027	5.00%	45.13
2028	5.00%	47.38
2029	5.00%	49.75
2030	5.00%	52.24

* Inflation: 1991-2000 from Data Resources Inc., Review of the U.S. Economy, Ten-year Projections, October 1990; 2001-2015 from Data Resources Inc., Review of the U.S. Economy, Long-Range Focus, Summer 1990; 2016-2030 set to 5%.

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The fixed firm avoided costs are the results of subtracting the variable firm avoided costs from the seasonal firm energy components determined for each period. Table V-2 shows the resulting fixed firm avoided costs.

Table V-2
Fixed Firm Avoided Costs
(mills/KWH)

	Total Firm Avoided Cost			Firm Avoided Cost w/o Variable Costs	
Year	Winter	Summer	Variable	Winter	Summer
1991	26.93	22.39	8.63	18.30	13.76
1992	29.53	24.55	8.94	20.59	15.61
1993	23.36	21.14	9.22	14.14	11.92
1994	25.09	23.01	9.51	15.58	13.50
1995	26.51	23.84	9.86	16.65	13.98
1996	45.67	37.97	10.24	35.43	27.73
1997	48.53	40.34	10.65	37.88	29.70
1998	51.65	42.94	11.08	40.57	31.86
1999	55.05	45.77	11.54	43.51	34.23
2000	58.77	48.86	12.04	46.73	36.82
2001	60.99	50.70	12.62	48.37	38.08
2002	63.40	52.71	13.25	50.15	39.46
2003	65.88	54.77	13.90	51.98	40.87
2004	68.49	56.94	14.58	53.91	42.36
2005	71.22	59.21	15.30	55.93	43.92
2006	74.09	61.60	16.04	58.05	45.55
2007	77.16	64.15	16.85	60.31	47.30
2008	80.45	66.88	17.71	62.74	49.18
2009	83.90	69.76	18.61	65.30	51.15
2010	87.54	72.77	19.56	67.98	53.22
2011	91.35	75.95	20.56	70.80	55.39
2012	95.36	79.28	21.60	73.76	57.68
2013	99.58	82.79	22.71	76.87	60.08
2014	104.10	86.54	23.89	80.21	62.66
2015	108.85	90.50	25.13	83.72	65.37
2016	113.66	94.49	26.39	87.27	68.11
2017	118.71	98.69	27.70	91.00	70.98
2018	124.01	103.10	29.09	94.92	74.01
2019	129.57	107.72	30.54	99.03	77.18
2020	135.42	112.58	32.07	103.34	80.51
2021	141.55	117.68	33.68	107.88	84.01
2022	147.99	123.04	35.36	112.63	87.68
2023	154.76	128.66	37.13	117.63	91.54
2024	161.86	134.57	38.98	122.88	95.58
2025	169.32	140.77	40.93	128.39	99.84
2026	177.16	147.29	42.98	134.18	104.31
2027	185.38	154.12	45.13	140.25	108.99
2028	194.01	161.29	47.38	146.63	113.91
2029	203.08	168.83	49.75	153.33	119.08
2030	212.60	176.75	52.24	160.36	124.51

VI. Final Forecast of Firm Avoided Costs

Table VI-1 sets forth the final fixed firm avoided cost forecast.

Table VI-1
Fixed Firm Avoided Cost Forecast

	Seasonal Fixed Firm Energy (mills/KWH)		
Year	Winter Sep-Mar	Summer Apr-Aug	Capacity ($/KW-month)
1991	18.30	13.76	4.36
1992	20.59	15.61	4.79
1993	14.14	11.92	0.00
1994	15.58	13.50	0.00
1995	16.65	13.98	0.00
1996	35.43	27.73	7.40
1997	37.88	29.70	7.86
1998	40.57	31.86	8.37
1999	43.51	34.23	8.92
2000	46.73	36.82	9.52
2001	48.37	38.08	9.88
2002	50.15	39.46	10.27
2003	51.98	40.87	10.68
2004	53.91	42.36	11.10
2005	55.93	43.92	11.54
2006	58.05	45.55	12.01
2007	60.31	47.30	12.50
2008	62.74	49.18	13.04
2009	65.30	51.15	13.60
2010	67.98	53.22	14.18
2011	70.80	55.39	14.80
2012	73.76	57.68	15.45
2013	76.87	60.08	16.14
2014	80.21	62.66	16.87
2015	83.72	65.37	17.64
2016	87.27	68.11	18.42
2017	91.00	70.98	19.23
2018	94.92	74.01	20.09
2019	99.03	77.18	21.00
2020	103.34	80.51	21.94
2021	107.88	84.01	22.94
2022	112.63	87.68	23.98
2023	117.63	91.54	25.08
2024	122.88	95.58	26.23
2025	128.39	99.84	27.44
2026	134.18	104.31	28.71
2027	140.25	108.99	30.04
2028	146.63	113.91	31.44
2029	153.33	119.08	32.91
2030	160.36	124.51	34.45