NHPUC Docket 09-137
Exhibit 10
UES Final Estimates

Contents:

Attachment 1: Revised Revenue Requirement Estimate for the SAU16 Project
Attachment 2: Revised Revenue Requirement Estimate for the Stratham Project
Attachment 3: Summary of Benefits and Costs for Stratham and SAU16 Projects
Attachment 4: 5YR Summary of Revenue Requirements for Ratemaking Purposes
Attachment 5: 5YR Estimated Rate Impacts
Attachment 6: LBR Estimation

Explanation:

Attachment 1: This attachment provides a calculation of the UES revenue requirements associated with its proposed $200,000 investment in the SAU16 project. The analysis assumes straight line depreciation/amortization over 20 years and includes a return on investment including working capital and income taxes, depreciation/amortization, and costs for EM&V and DER Program Expense. The non-utility project related costs are added including debt service and repayment and O&M costs. A credit is shown for the investment tax credits which serve as an offset to the project costs. The expected lifetime for the microturbine is 15 years and for the PV system 20 years. The model calculates a cumulative NPV cost of $1,281,713.

Attachment 2: This attachment provides the calculation of the UES revenue requirements associated with its proposed investment in the Stratham project. This caculation has not changed from the presentation in Exhibit 5. The model calculates a cumulative NPV cost of $516,671.

Attachment 3: This attachment summarizes the benefits for the Stratham and SAU16 projects, and shows the resulting benefit cost ratios for various calculations. The Attachment also shows the benefits and ratios for the two projects taken together. Several factors have been updated in the benefits calculations, including the following:

Stratham: A benefit reduction is included due to the fact that the project will not provide a reduction in RPS compliance obligation, while the Synapse avoided energy cost numbers include such a reduction. The value is based on the estimate provided by Staff Witness McCluskey.

SAU16: The modelling reflects an assumption of a 20 year life for the PV system and a 15 year life for the microturbine. The microturbine is not eligible for RECs, however both components of the project contribute to a reduction in RPS compliance obligations (that reduction is assumed in the Synapse avoided energy cost numbers).

Attachment 4: This attachment summarizes the estimated UES revenue requirements for the first five years, for purposes of estimating rate impacts. In addition to the UES revenue requirements calculated in Attachments 1 and 2, the schedule also includes the outside consulting costs associated with DER program start-up and an estimate of the annual expenses relating to DER program activities - net of the expenses already included in the project revenue requirements.

Attachment 5: This attachment provides a calculation of the rate impact from the proposed DER projects and expenses for a five year period. The rate impact is shown relative to a typical residential monthly bill of $75.13.

Attachment 6: This attachment provides an LBR calculation for the value included in Attachment 5.

Updated Estimate of Revenue Requirement - SAU16 Project

PV total Cost = $625K; Turbine Total Cost = $235K
UES investment = 200K; SAU16 investment = 660K

Estimated Direct Cost to UES		200,000	UES cost only - SAU16 share factored in below
Estimated UES Cost (AFUDC plus Gen OH	1.55%	3,105	Estimated 3mos AFUDC at 2.21%, plus 1% OHD
UES Total Investment		203,105	
Customer Contribution		0	
Investment Tax Credit	0%	0	Offset to SAU16 costs - 30% on PV and 10% on microturbine
Net UES Investment		203,105	-
Depreciation Basis Adjustment	50%	203,105	
Investment Life	20		20 year life for PV; 15 yrs for microturbine (O&M includes new PV inverter and turbine overhauls)
UES Effective Income Tax Rate	39.61%		Effective rate
UES Pre-Tax Rate of Return	11.18%		YR End 2009 estimate
UES After Tax Rate of Return	8.37%		YR End 2009 estimate
SAU16 Debt Costs	See below		George McCluskey Testimony
UES EM&V and Share of DER Program Ex	2.00%		
Other O&M	See below		George McCluskey Testimony
Working Capital days	12		George McCluskey Testimony
Discount Rate	3.25%		CORE EE Assumption
Inflation Rate	1.56%		CORE EE Assumption
Default Service Inflation Rate	2.92%		Caculated from Synapse Table

	1	2	3	4	5	6	7	8	9	10	11	12	13	14	15	16	17	18	19	20
Tax Depreciation Schedule (20yr amort)	5.00%	5.00%	5.00%	5.00%	5.00%	5.00%	5.00%	5.00%	5.00%	5.00%	5.00%	5.00%	5.00%	5.00%	5.00%	5.00%	5.00%	5.00%	5.00%	5.00%
Return on Investment:																				
Plant Investment (no ITC basis adj)	203,105	203,105	203,105	203,105	203,105	203,105	203,105	203,105	203,105	203,105	203,105	203,105	203,105	203,105	203,105	203,105	203,105	203,105	203,105	203,105
Book Depreciation (Amortization)	10,155	10,155	10,155	10,155	10,155	10,155	10,155	10,155	10,155	10,155	10,155	10,155	10,155	10,155	10,155	10,155	10,155	10,155	10,155	10,155
Depreciation Reserve EOY (no ITC basis adj)	10,155	20,311	30,466	40,621	50,776	60,932	71,087	81,242	91,397	101,553	111,708	121,863	132,018	142,174	152,329	162,484	172,639	182,795	192,950	203,105
Book Depreciation (ITC basis adj)	10,155	10,155	10,155	10,155	10,155	10,155	10,155	10,155	10,155	10,155	10,155	10,155	10,155	10,155	10,155	10,155	10,155	10,155	10,155	10,155
Tax Depreciation (ITC basis adj)	10,155	10,155	10,155	10,155	10,155	10,155	10,155	10,155	10,155	10,155	10,155	10,155	10,155	10,155	10,155	10,155	10,155	10,155	10,155	10,155
Timing Difference (tax-book ITC basis adj)	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
Deferred Taxes (ITC basis adj)	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
Deferred Tax Reserve EOY (ITC basis adj)	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
Net Plant EOY (no ITC basis adj)	192,950	182,795	172,639	162,484	152,329	142,174	132,018	121,863	111,708	101,553	91,397	81,242	71,087	60,932	50,776	40,621	30,466	20,311	10,155	0
Average Net Plant	198,027	187,872	177,717	167,562	157,406	147,251	137,096	126,941	116,785	106,630	96,475	86,320	76,164	66,009	55,854	45,699	35,543	25,388	15,233	5,078
Working Capital Addition	6,510	6,177	5,843	5,509	5,175	4,841	4,507	4,173	3,840	3,506	3,172	2,838	2,504	2,170	1,836	1,502	1,169	835	501	167
Net Rate Base	204,538	194,049	183,560	173,071	162,581	152,092	141,603	131,114	120,625	110,136	99,647	89,158	78,668	68,179	57,690	47,201	36,712	26,223	15,734	5,245
Pre-Tax Return (incl Inc Tax)	22,867	21,695	20,522	19,349	18,177	17,004	15,831	14,659	13,486	12,313	11,140	9,968	8,795	7,622	6,450	5,277	4,104	2,932	1,759	586
Expenses:																				
EM&V and Share of DER Program Exp	4,062	4,125	4,190	4,255	4,322	4,389	4,457	4,527	4,598	4,669	4,742	4,816	4,891	4,968	5,045	5,124	5,204	5,285	5,367	5,451
Book Depreciation (Amortization)	10,155	10,155	10,155	10,155	10,155	10,155	10,155	10,155	10,155	10,155	10,155	10,155	10,155	10,155	10,155	10,155	10,155	10,155	10,155	10,155
SAU16 Costs:																				
Non-utility O&M	18,800	19,093	19,391	19,694	20,001	20,313	20,630	20,952	21,278	21,610	21,947	22,290	22,638	22,991	23,349	13,118	13,323	13,531	13,742	13,956
Non-utility debt principal and interest (10yr PV, 5yr Turbine, 7% interest)	122,133	116,659	111,185	105,711	100,237	65,750	62,250	58,750	55,250	51,750	0	0	0	0	0	0	0	0	0	0
ITC:																				
Amortization of ITC - SAU16 cost offset	19,220	19,220	19,220	19,220	19,220	18,750	18,750	18,750	18,750	18,750	0	0	0	0	0	0	0	0	0	0
Total Annual Costs	158,798	152,508	146,223	139,944	133,671	98,861	94,574	90,292	86,017	81,748	47,985	47,229	46,479	45,736	44,999	33,674	32,786	31,903	31,024	30,149
NPV (beginning of year)	156,278	145,364	134,987	125,124	115,753	82,914	76,822	71,036	65,542	60,328	34,298	32,694	31,163	29,699	28,301	20,512	19,342	18,229	17,168	16,159
CUMULATIVE	1,281,713																			

Updated Estimate of Revenue Requirement - Stratham Project

NHPUC Docket 09-137
Exhibit 10 Attachment 2

Estimated Direct Cost		271,200						Estimated at PSNH Solar PV Array Cost \$6.78/kw, 40 kw
Estimated UES Cost (AFUDC plus Gen OH)	1.55%	4,210						Estimated 3mos AFUDC at 2.21%, plus 1% OHD
Total Investment		275,410						-
Customer Contribution		0						Utility owned.
Investment Tax Credit	30%	0						ITC calculation below - method provided by PSNH
Net UES Investment		275,410						-
Depreciation Basis Adjustment	50%	234,099						Depreciable basis for renewable projects reduced by half of ITC
Investment Life	20							20 year life
Effective Income Tax Rate	39.61%							Effective rate
Pre-Tax Rate of Return	11.18%							YR End 2009 estimate
After Tax Rate of Return	8.37%							YR End 2009 estimate
Tax Depreciation Schedule	20.00%	32.00%	19.20%	11.52%	11.52%	5.76%	0.00%	Five year MACRS allowed for solar PV
Lease pmnt	\$4,600							Tom Palma Testimony
EM&V and Share of DER Program Exp	2.00%							George McCluskey Testimony
Other O&M	See below							Tom Palma Testimony
Working Capital days	12							George McCluskey Testimony
Discount Rate	3.25%							CORE EE Assumption
Inflation Rate	1.56%							CORE EE Assumption
Default Service Inflation Rate	2.92%							Caculated from Synapse Table

	1	2	3	4	5	6	7	8	9	10	11	12	13	14	15	16	17	18	19	20
Return on Investment:																				
Plant Investment (no ITC basis adj)	275,410	275,410	275,410	275,410	275,410	275,410	275,410	275,410	275,410	275,410	275,410	275,410	275,410	275,410	275,410	275,410	275,410	275,410	275,410	275,410
Book Depreciation (no ITC basis adj)	13,771	13,771	13,771	13,771	13,771	13,771	13,771	13,771	13,771	13,771	13,771	13,771	13,771	13,771	13,771	13,771	13,771	13,771	13,771	13,771
Depreciation Reserve EOY (no ITC basis adj)	13,771	27,541	41,312	55,082	68,853	82,623	96,394	110,164	123,935	137,705	151,476	165,246	179,017	192,787	206,558	220,328	234,099	247,869	261,640	275,410
Book Depreciation (ITC basis adj)	11,705	11,705	11,705	11,705	11,705	11,705	11,705	11,705	11,705	11,705	11,705	11,705	11,705	11,705	11,705	11,705	11,705	11,705	11,705	11,705
Tax Depreciation (ITC basis adj)	46,820	74,912	44,947	26,968	26,968	13,484	0	0	0	0	0	0	0	0	0	0	0	0	0	0
Timing Difference (tax-book ITC basis adj)	35,115	63,207	33,242	15,263	15,263	1,779	-11,705	-11,705	-11,705	-11,705	-11,705	-11,705	-11,705	-11,705	-11,705	-11,705	-11,705	-11,705	-11,705	-11,705
Deferred Taxes (ITC basis adj)	13,909	25,036	13,167	6,046	6,046	705	-4,636	-4,636	-4,636	-4,636	-4,636	-4,636	-4,636	-4,636	-4,636	-4,636	-4,636	-4,636	-4,636	-4,636
Deferred Tax Reserve EOY (ITC basis adj)	13,909	38,945	52,112	58,158	64,204	64,909	60,272	55,636	51,000	46,363	41,727	37,091	32,454	27,818	23,182	18,545	13,909	9,273	4,636	0
Net Plant EOY (no ITC basis adj)	247,731	208,924	181,987	162,170	142,354	127,879	118,744	109,610	100,476	91,342	82,208	73,074	63,939	54,805	45,671	36,537	27,403	18,268	9,134	0
Average Net Plant	261,571	228,328	195,455	172,078	152,262	135,116	123,312	114,177	105,043	95,909	86,775	77,641	68,506	59,372	50,238	41,104	31,970	22,835	13,701	4,567
Working Capital Addition	8,600	7,507	6,426	5,657	5,006	4,442	4,054	3,754	3,453	3,153	2,853	2,553	2,252	1,952	1,652	1,351	1,051	751	450	150
Net Rate Base	270,170	235,834	201,881	177,736	157,268	139,558	127,366	117,931	108,497	99,062	89,628	80,193	70,759	61,324	51,890	42,455	33,021	23,586	14,152	4,717
Pre-Tax Return (incl Inc Tax)	30,205	26,366	22,570	19,871	17,583	15,603	14,239	13,185	12,130	11,075	10,020	8,966	7,911	6,856	5,801	4,746	3,692	2,637	1,582	527
Expenses:																				
Lease pmnt (esc. @ default svc)	4,600	4,734	4,873	5,015	5,161	5,312	5,467	5,627	5,791	5,960	6,134	6,313	6,498	6,687	6,883	7,084	7,290	7,503	7,722	7,948
EM&V and Share of DER Program Exp	5,508	5,594	5,681	5,770	5,860	5,951	6,044	6,139	6,234	6,332	6,430	6,531	6,633	6,736	6,841	6,948	7,056	7,166	7,278	7,392
Other O&M (incl. inverter yr 11)	500	508	516	524	532	540	549	557	566	575	41,895	593	602	611	621	631	641	500	500	500
Depreciation (no ITC basis adj)	13,771	13,771	13,771	13,771	13,771	13,771	13,771	13,771	13,771	13,771	13,771	13,771	13,771	13,771	13,771	13,771	13,771	13,771	13,771	13,771
ITC:																				
Amortization of ITC over 20 yrs	4,131	4,131	4,131	4,131	4,131	4,131	4,131	4,131	4,131	4,131	4,131	4,131	4,131	4,131	4,131	4,131	4,131	4,131	4,131	4,131
Tax Gross Up	2,710	2,710	2,710	2,710	2,710	2,710	2,710	2,710	2,710	2,710	2,710	2,710	2,710	2,710	2,710	2,710	2,710	2,710	2,710	2,710
Grossed Up ITC	6,841	6,841	6,841	6,841	6,841	6,841	6,841	6,841	6,841	6,841	6,841	6,841	6,841	6,841	6,841	6,841	6,841	6,841	6,841	6,841
Revenue Requirement	47,743	44,132	40,570	38,109	36,066	34,336	33,229	32,437	31,651	30,871	71,410	29,332	28,573	27,821	27,076	26,338	25,609	24,736	24,012	23,297
NPV (beginning of year)	46,986	42,065	37,452	34,073	31,231	28,798	26,992	25,519	24,117	22,782	51,040	20,305	19,157	18,066	17,028	16,043	15,108	14,134	13,288	12,486
CUMULATIVE	516,671																			

Exhibit 10 Attachment 3

	Stratham Total Resource Cost Final UES Estimates	SAU 16 Total Resource Cost Final UES Estimates <microturbine and PV>	DER Portfolio Total Resource Cost Final UES Estimates	
Key Assumptions				
Lifetime	20 years	20yrsPV;15yrsturbine		
KW	40	143		
KWH	52,000	453,400		
Cap Factor (%)	14.80%	36.32%		
Inventory of Benefits	Value:			**Notes:**
Capacity				
Generation *	$ 56,716	$ 165,443	$ 222,159	Synapse AESC; Increased for FCM value.
Transmission	$ 66,897	$ 54,684	$ 121,581	Valued at UES marginal cost.
Distribution	$ 59,127	$ 167,956	$ 227,083	Valued at UES marginal cost.
DRIPE *	$ 6,779	$ 24,150	$ 30,929	Synapse AESC.
Localized Distribution	$ -			Non-direct benefit.
Total Capacity	**$ 189,518**	**$ 412,233**	**$ 601,752**	
Energy				*Values based on the Synapse Avoided Energy Supply Costs 2009 Report.
Winter				
Peak *	$ 20,730	$ 269,583	$ 290,313	
Off Peak *	$ 26,969	$ 178,266	$ 205,235	
Summer				
Peak *	$ 10,873	$ 49,086	$ 59,959	
Off Peak *	$ 13,001	$ 36,854	$ 49,855	
Total Energy	**$ 71,573**	**$ 533,790**	**$ 605,363**	
Other				
Energy DRIPE *	$ 15,515	$ 145,117	$ 160,632	Synapse AESC.
CO2	$ -		$ -	Non-direct benefit.
REC Value	$ 133,672	$ 378,908	$ 512,580	Estimated at 75% of ACP for PV only.
RPS Comp	$ (19,549)		$ (19,549)	Included in Synapse AESC.
Economic Development	$ -		$ -	Non-direct benefit.
Total Other	**$ 129,638**	**$ 524,025**	**$ 653,663**	
Total Direct Benefits	$ 390,729	$ 1,470,048	$ 1,860,778	
Total Estimated Lifetime Costs	$ 516,671	$ 1,281,713	$ 1,798,384	
Benefit/Cost Ratio	0.76	1.15	1.03	
Non-Direct Benefits				
Economic Development	$ 426,282	$ 364,570	$ 790,852	Howard Axelrod Testimony
Additional CO2 reduction value	$ 27,446	$ 238,233	$ 265,679	Howard Axelrod Testimony
Local system capacity value	$ 3,307	$11,780	$ 15,087	Howard Axelrod Testimony
Total Non-Direct Benefits	$ 457,035	**$ 614,583**	**$ 1,071,618**	
Calculation of Benefit Cost Ratio including Non-Direct Benefits at 100%				
Total Benefits	$ 847,764	$ 2,084,631	$ 2,932,396	
Benefit/Cost Ratio	1.64	1.63	1.63	
Calculation of Benefit Cost Ratio including Non-Direct Benefits at 50%				
Total Benefits	$ 619,247	$ 1,777,340	$ 2,396,587	
Benefit/Cost Ratio	1.20	1.39	1.33	
Calculation of Benefit Cost Ratio including Non-Direct Benefits at 25%				
Total Benefits	$ 504,988	$ 1,623,694	$ 2,128,682	
Benefit/Cost Ratio	0.98	1.27	1.18	

Unitil Energy Systems, Inc.
DER Projects - Revenue Requirement Summary
Illustrative Example

NHPUC Docket 09-137
Exhibit 10 Attachment 4

A	B	C	D	E	F	G	H
Yr	Crutchfield Solar DHW System	Stratham Municipal Solar PV	SAU 16 Solar PV and Micro-Turbine CHP	Time of Use Pilot Program	DER Start-up Consulting Services	Ongoing Program Management and Reporting (1)	Total Revenue Requirement
1	$ -	$ 47,743	$ 37,085	$ -	$ 120,000	$ 135,640	$ 340,467
2	-	44,132	35,975	-	-	137,756	217,863
3	-	40,570	34,867	-	-	141,200	216,636
4	-	38,109	33,760	-	-	144,730	216,598
5	-	36,066	32,653	-	-	148,348	217,067

(1) Based on original expense estimate - EMV values included in Stratham and SAU16 RR have been deducted.

DE 09-137
Unitil Energy Systems, Inc.
Distributed Energy Resources Investment Proposal
Estimated Residential 500 kWh Bill Impact for First 5 Years

NHPUC Docket 09-137
Exhibit 10 Attachment 5

			2010	2011	2012	2013	2014
1	Estimated Revenue Requirement ("RR")		$ 340,467	$ 217,863	$ 216,636	$ 216,598	$ 217,067
2	Estimated Offset Revenues ("OR") - Note (1)		$ (6,633)	$ (6,736)	$ (6,842)	$ (8,844)	$ (8,982)
3	Estimated Lost Base Revenue ("LBR") - Note (2)		$ 4,865	$ 4,941	$ 5,018	$ 5,096	$ 5,176
4	Estimated Reconciliation Adjustment ("RA")		$ -	$ -	$ -	$ -	$ -
5	Estimated Interest ("I") - Note (3)		$ -	$ -	$ -	$ -	$ -
6	Total Costs to Recovered (Sum Lines 1 through 5)		$ 338,699	$ 216,068	$ 214,813	$ 212,850	$ 213,260
7	Estimated Calendar Year kWh delivered ("FkWh")		1,219,706,756	1,239,261,677	1,259,582,107	1,273,015,505	1,290,045,591
8	Distributed Energy Resources Investment Charge ("DERIC") (Line 6 / Line 7)		$ 0.00028	$ 0.00018	$ 0.00017	$ 0.00017	$ 0.00017
9	Impact to Residential 500 kWh Bill (Line 8 * 500)		$ 0.14	$ 0.09	$ 0.09	$ 0.09	$ 0.08
10	Current Residential 500 kWh Bill	$ 75.13					
11	Percent Impact to Current Bill (Line 9 / Line 10)		0.2%	0.1%	0.1%	0.1%	0.1%

(1) Based on estimated RECs at $45/MWH year 1, plus FCM revenues at Synapse forecast beginning yr 2013, plus inflation
(2) Estimate for SAU16 Project only - escalated at inflation.
(3) Estimated carrying cost factored into RR

Unitil Energy Systems, Inc.
Distributed Energy Resources Investment Proposal
Projected Lost Base Revenue for 2010

NHPUC Docket 09-137
Exhibit 10 Attachment 6

	Installation Type (1)	Rate Class (2)	Monthly kWh/kW Reduction (3)	Coincidence With Peak Demand (4)	kWh/kW Savings (5)	Distribution Rate (6)	Monthly Lost Revenue (7)	Annual Lost Revenue (8)
Crutchfield Place	Solar Domestic Hot Water	Residential D	-		-	$ 0.02310	$ -	$ -
Stratham Municipal	Solar PV	General G2	0.0	80%	-	$ 7.03	$ -	$ -
Exeter SAU 16	Solar PV	General G1	80.0	50%	40.0	$ 5.69	$ 228	$ 2,731
Exeter SAU 16	Micro Combined Heat and Power	General G1	62.5	50%	31.3	$ 5.69	$ 178	$ 2,134
Time of Use Program	n/a	Residential D	-		-	$ 0.02310	$ -	$ -
Total							$ 405	$ 4,865

Col. (3) Residential D monthly reductions are stated in kWh and General G2 and G1 monthly reductions are stated in kW.
Col. (4) = Estimateed average coincidence with Customer Peak metered demand.
Col. (5) = Col. (3) * Col. (4)
Col. (6) = Distribution rates in effect August 1, 2009, Residential reflects 2nd block kWh rate. G1 rate is per kVa. Calculation assumes 100% power factor.
Col. (7) = Col. (5) * Col. (6)
Col. (8) = Col. (7) * 12