Review of Prospects and Strategies for the 2012 Avista Regular Income Natural Gas DSM Portfolio

Introduction

Avista's 2012 Demand Side Management (DSM) Business Plan, submitted on November 1st 2011, identified a natural gas DSM portfolio that was projected to be cost-ineffective under the total resource cost (TRC) test. Benefit to cost test ratios were estimated to be 0.63 for the regular income (excluding the low income programs) and 0.54 for the total natural gas portfolio (including low income programs). Benefits to cost ratios below 1.00 indicate that the costs exceed the benefits and that the portfolio is not cost-effective.

The acquisition of the natural gas DSM portfolio was similarly disappointing. A total of 1.2 million (first-year impact) therms were expected to be achieved. This was only 50% of the acquisition target established in the prior Integrated Resource Plan (IRP).

The performance of the portfolio has been substantially impacted by adverse economic conditions, falling retail rates (therefore reducing participant economics and customer interest) and federal funding for efficiency projects in prior years (which accelerated the acquisition into prior years at the expense of 2012 potential).

Traditionally the Company would undertake an iterative process to improve the cost-effectiveness to be fielded during the following year. This would involve terminating or redesigning measures not meeting performance expectations, enhancing successful programs, launching new promising programs and refining the infrastructure costs borne by the portfolio. Unfortunately, late revisions to the Company's electric conservation potential assessment (CPA) and a fixed deadline for the final work product didn't permit sufficient time for this process to be fully carried out. The Company committed to performing an optimization process to improve the performance of the natural gas DSM portfolio and submit a report detailing this process. This report embodies the recommendations made, management actions and the expected results of that optimization process.

This optimization process has not included the performance of the low-income portion of the natural gas DSM portfolio. A review of the low-income DSM portfolio is expected to occur during the spring of 2012 within Avista's Idaho and Washington jurisdiction. The policy issues and metrics that the low-income portfolio will be judged by are substantially different than those faced by the remainder of the portfolio, as are the means by which this portfolio is delivered. These differences call for a separate effort specific to these unique issues.

Overview

The portfolio analyzed and submitted within the 2012 DSM Business Plan was a portfolio which had not been optimized for a very different economic environment. The task of this process is to incorporate revised retail rates, updates to the energy savings documented within the Company's Technical Resource Manual (TRM) and both current and projected avoided cost streams.

More than any single factor, it is the substantial shift in avoided cost streams that drive the changes in the direction of this portfolio. The avoided costs used within the 2012 DSM Business Plan and also applied within portions of this report are based upon the most recent Commission recognized IRP. Though these avoided costs are relative to electric avoided costs and place an upper limit upon what measures can be cost-effectively offered, observed trends in natural gas commodity prices clearly indicate that the 2012 natural gas IRP will yield substantially lowered avoided costs. For purposes of this report, a lower avoided cost scenario which we will term the 'projected' avoided cost, will be included.

The projected avoided costs are assumed to be 25% lower than current avoided costs. The process will apply the current avoided costs to 2012 operations and projected avoided costs to 2013 operations. The 2013 operations are assumed to be typical of all years beyond 2012.

It should be recognized that all avoided cost estimates are clearly subject to error. This is even truer when we are projecting the avoided costs to be identified in a future IRP process. Thus, we will seek to take into consideration both the risk reduction value of DSM resources with particular attention to 'lost opportunity' measures (those that cannot be reacquired for an extended period of time if they are not acquired now). The Company is planning to assess the potential for quantifying these risk values, perhaps using methodologies similar to those used within the establishment of electric avoided costs used for purposes of evaluating DSM measures, upon the completion of the natural gas IRP. For purposes of this process it is necessary to incorporate these considerations in a qualitative rather than a quantitative manner.

The report will evaluate the overall Washington and Idaho jurisdiction portfolios. The DSM programs offered are, with rare exceptions, identical in both states and the evaluation results have proven to be very similar for the regular income portfolio. The Company will seek to maximize the residual TRC benefit of the portfolio by pursuing all measures and programs that are incrementally cost-effective. This process is specifically not seeking to achieve any numeric acquisition target (including both targets established by previous IRPs or Washington decoupling targets). It is certain that improving the cost-effectiveness of the portfolio can only be achieved by reducing the size of the portfolio, in terms of both measures and programs offered as well as total acquisition achieved.

Where it is useful, both gross (representing all programmatic participants) and net (representing only those participants motivated to adopt an efficiency measure due to the utility program) are estimated. Net-to-gross ratios (the percentage of program participants who installed the measure due to the utility program influence) are based upon a recent 2010 net-to-gross study produced by the Cadmus Group and specific to Avista's portfolio and customers.

It is assumed for purposes of this process that the Company will receive approval of a series of DSM tariffs that remain under review by the Company's Advisory Group. The proposed revisions to the tariffs would allow greater flexibility in the incentive level that may be set for prescriptive programs. These incentives would no longer be expected to generally conform to the formulaic incentive guidance used for the Company's site-specific program and incorporated into the current tariffs. Should this additional flexibility not be available for 2013 programs it is likely that the prescriptive programs will deliver somewhat lower levels of acquisition, though it is unlikely that their TRC cost-effectiveness will be materially affected.

Cost-Effectiveness Metrics and Cost Allocation

The portfolio optimization process will employ what the Company has termed a 'sub-TRC" calculation at each stage of aggregation of the portfolio. This calculation recognized the benefits and costs that are incremental at each level of aggregation.

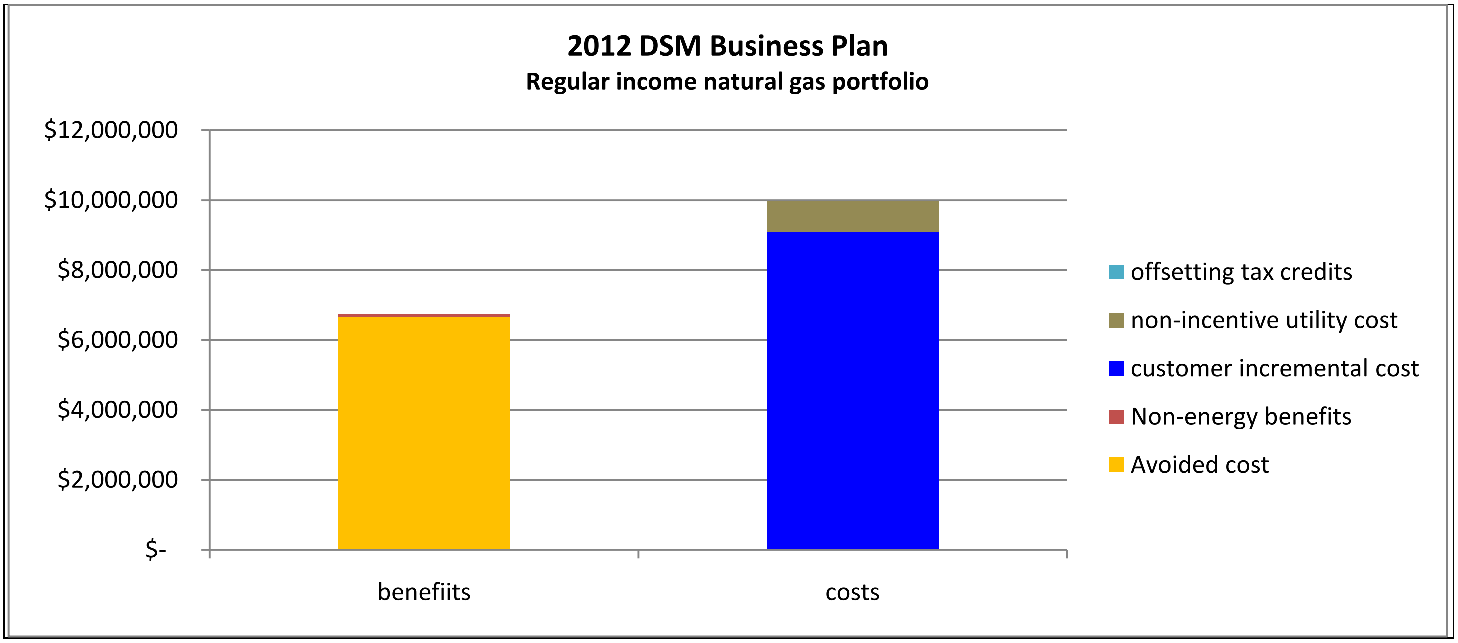
The lowest level of aggregation consists of individual efficiency measures. At this level of aggregation all benefits are considered to be incremental as well as customer incremental costs. Non-incentive utility costs are not usually considered to be incremental costs at the measure level.

Measures are subsequently aggregated into programs. There are no additional benefits at the program level, but utility labor and many administrative costs are primarily allocated at the program level. While some programs are directly assigned labor costs when the costs are directly related to that program, other labor costs may be allocated based upon the avoided cost benefit of the program.

Programs are aggregated into an overall natural gas DSM portfolio (or regular income portfolio for purposes of this optimization process). Though there are no benefits that are incremental at this level of aggregation, all remaining non-incentive utility costs (primarily the CPA process and evaluation, measurement and verification (EM&V)) are incorporated into the portfolio TRC costs.

Figure 1, below, illustrates the 2012 expectations for the costs and benefits of the regular income natural gas DSM portfolio at the completion of the 2012 DSM Business Plan.

Figure 1: Natural gas portfolio TRC benefits and costs



Approaching the optimization in this manner allows for the review of each measure and program based upon the incremental benefits that it brings to the entire portfolio. Inappropriately burdening the measures and programs with infrastructure and overhead costs that are not incremental to that calculation could incorrectly lead to the exclusion of components that favorably impacts the overall portfolio.

The allocation of joint electric and natural gas DSM portfolio costs are based upon the avoided cost values of the relative portfolios. This allocation most frequently occurs in 'dual-fuel' projects (measures simultaneously yielding both electric and natural gas efficiencies) and non-incentive utility costs that cannot be directly assigned to either portfolio.

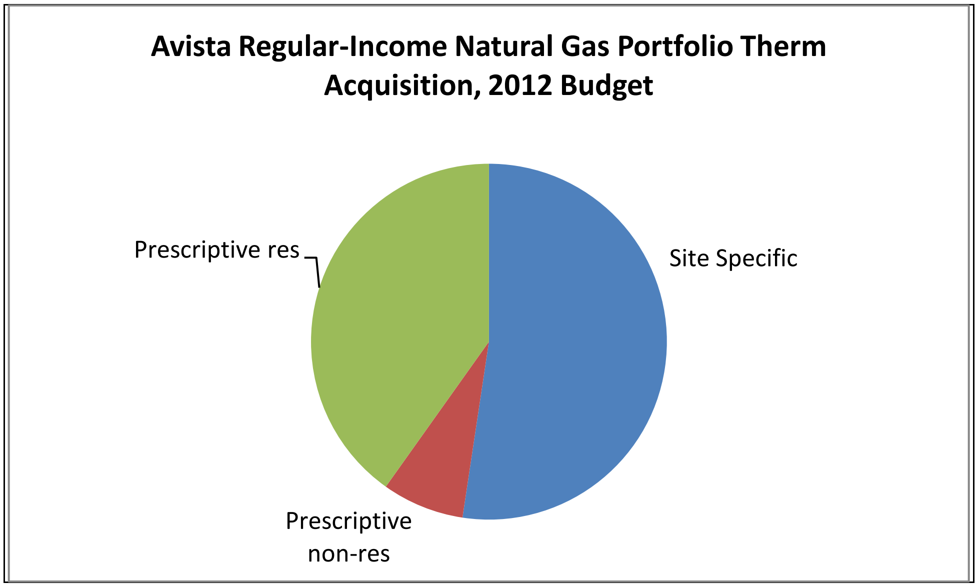
Portfolio components

The overall natural gas DSM portfolio can be categorized in several different ways. For purposes of this optimization process three separate categories have been defined; (1) the site-specific program, (2) the non-residential prescriptive program and (3) the residential prescriptive program.

A discussion of the role of a prospective regional market transformation program will be included within this report. Since the timing of the costs and benefits are not aligned for the 2012 and 2013 periods (costs have been budgeted for this activity but the benefits will not occur until a later date) this has not been included in the cost-effectiveness analysis. The regional market transformation program is suitable for a separate discussion with the Advisory Group as investment decisions occur.

Figure 2, below, represents the distribution of the 2012 expected therm acquisition proposed within the 2012 DSM Business Plan.

Figure 2: Previously projected 2012 therm acquisition



The Site-Specific Program

Avista's site-specific program is an "all-comers" program under which any measure delivering quantifiable therm savings qualifies. Effective on January 1, 2011 incentives have been limited to projects with an energy simple payback of between 1 and 13 years. Projects which are under 1 year energy simple payback receive technical support and are included within cost-effectiveness calculations. Projects which are over a 13 year energy simple payback are evaluated however, upon the determination that they are beyond the scope of the incentive provisions of the tariff, receive only customer information support and will not be incorporated into the cost-effectiveness evaluation.

An exception to this rule is for projects with an energy simple payback in excess of 13 years, based upon a written transition policy enacted to deal with projects that had been contracted or were in the contracting process at the time the revised tariffs became effective. These projects, termed "legacy" projects within this report, are incorporated into the cost-effectiveness calculations. The general provisions of that transition policy can be summarized as follows:

(1) projects contracted by April 31, 2011 must complete by December 31, 2011 unless a later date is permitted based upon the conditions below,
    a. projects contracted by April 31, 2011 that could not be completed by December 31, 2011 due to construction time requirements have until December 31, 2012 to complete; and
    b. projects contracted by April 31, 2011 and requiring board or voter approval and with energy simple paybacks 20 years or less have until December 31, 2015 to complete.

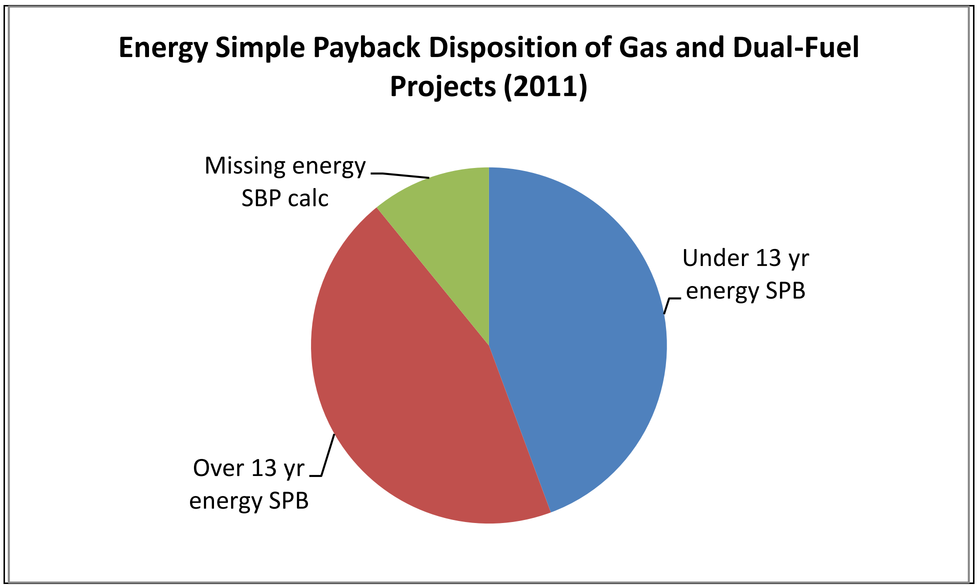
It is expected that the vast majority of these legacy projects will complete during 2012 and will not materially influence the natural gas DSM portfolio beyond that date. This optimization process was able to use updated year-end contract status on a number of these projects to improve the estimates previously made within the 2012 DSM Business Plan.

Based upon the above information, it was found that fewer legacy projects will be carried forward into 2012 than previously estimated, but the projects that are continuing forward are larger in size.

The 2012 projections include estimates of the likelihood of these pre-existing contractual obligations to complete during that year. In order to facilitate the management of these contractual obligations the Company has identified those projects which will be incentivized if they successfully complete in 2012 based upon the provisions of the written transition policy. Those projects that are authorized for 2012 completion should be issued updated contracts with the appropriate end-date. Also, customers with projects that are no longer authorized for payment beyond December 31, 2011 have been, or will be notified that their contracts have expired and will not be renewed. Those contracts that may be permitted completion dates beyond the end of 2012 should be similarly inventoried and contracted with appropriate communications to customers.

The categorizations of the contracts in place at the close of 2011 are shown below. This categorization does not include projects that will contract after the close of 2011, all of which will have energy simple paybacks under 13 years.

Figure 3: Site-specific project distribution by energy simple payback



The calculation of the energy simple payback is also based upon a written policy. The energy simple payback is based upon the customer's energy savings at retail rates relative to the incremental cost of the efficiency project. The policy outlines other issues such as salvage and disposal costs, aggregation vs. separation of project components, combined electric and natural gas projects and other issues. This policy is closely linked to the "Dual-Fuel Incentive Calculator", which is a spreadsheet-based model ensuring that the incentives for site-specific projects are consistently calculated.

This optimization process is taking a two year view of the natural gas DSM portfolio largely to allow for the separation of the impact of existing contractual obligations of the site-specific program and the results of prescriptive programs that are in the process of being terminated. Thus the analysis of the site-specific program will distinguish between the legacy and the remaining projects qualifying under the current tariff. For purposes of projecting 2013 operations, the legacy site-specific projects will be assumed to no longer play a significant role in the portfolio.

Analysis of the site-specific program

For the site-specific program, the Company has chosen to use the energy simple payback tool as the primary means for both differentiating cost-effective and cost-ineffective projects as well as managing the net-to-gross ratio by targeting incentive funds for those projects where it is most likely to make a difference in the customers investment decision. Any optimization process should naturally include an assessment over whether the use of this tool is effective at achieving the desired cost-effectiveness objective.

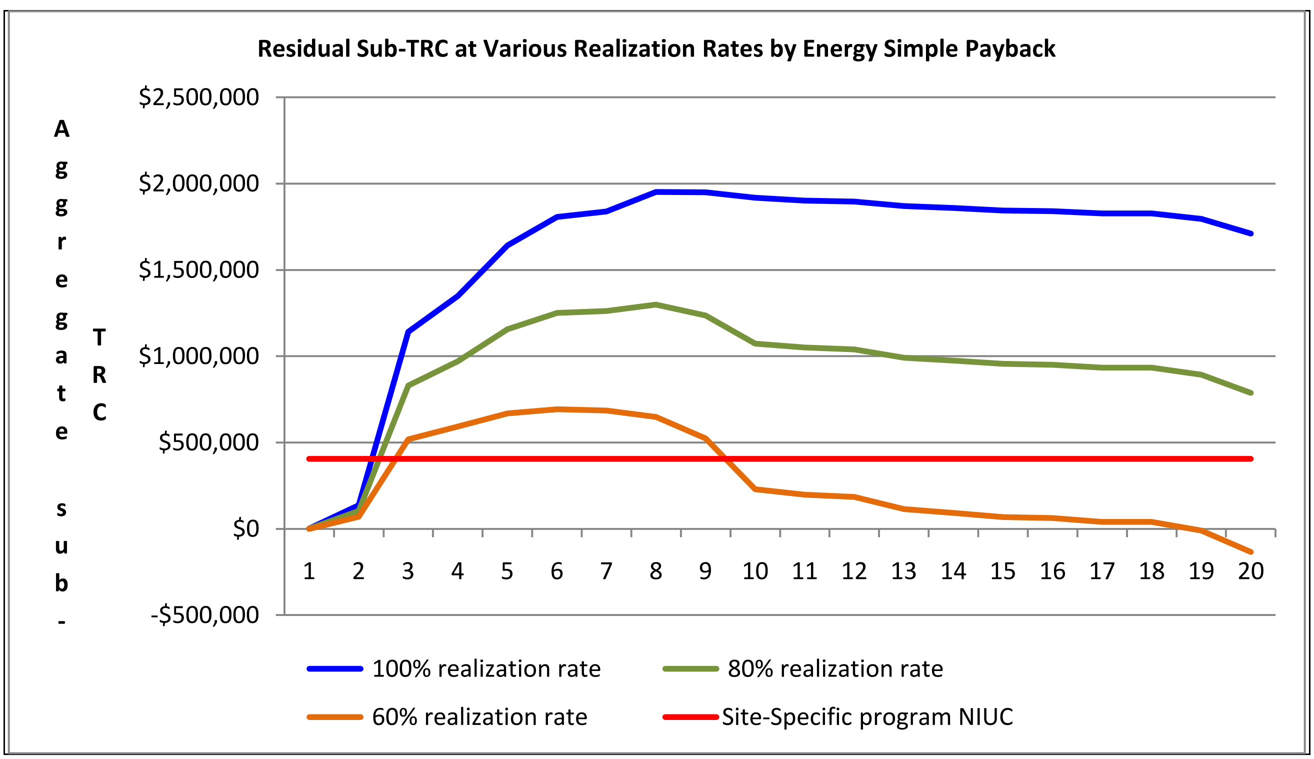
It should be noted that the energy simple payback calculation used within the site-specific program does not consider measure life (beyond the requirement that all projects have a measure life of at least ten years) nor does it include non-energy benefits. Thus the energy simple payback is closely tied to the TRC cost-effectiveness of the project, but that relationship is not perfect.

This report was able to utilize updated (since the completion of the DSM Business Plan), data regarding contracted site-specific projects. In addition to an inventory of year-end 2011 contracts it was also possible to estimate the characteristics of 2012 contracted projects based upon what was observed from 2011 project completions.

Using 144 project completions in 2011 it is possible to calculate how a portfolio of those projects would perform based upon different energy simple payback eligibility standards. If the current energy simple payback eligibility standard does not adequately differentiate cost-effective and non-cost-effective projects, or if the 13 year eligibility criteria is incorrectly set, the site-specific programs performance would be hindered.

Figure 4 below illustrates the gross (without consideration of net-to-gross ratio) level of residual TRC benefits (TRC benefits less TRC costs) for projects at or below the specified energy simple payback. Three realization rates are reflected (100%, 80% and 60%) to illustrate the sensitivity of the as-yet unverified 2011 results to different realization rates.

Figure 4: Residual TRC benefits across energy simple payback periods and realization rates



Note: Energy simple paybacks are locked at pre-verification levels. The sub-TRC values are changed based upon alternative realization rates.

The horizontal line represents an initial estimate of the non-incentive utility costs that would be assigned to the natural gas site-specific program (predominately labor costs) under the assumptions of the 2012 DSM Business Plan. Falling below this line would indicate that the program would be unfavorably impacting the cost-effectiveness of the total portfolio. Ideally the energy simple payback eligibility criteria would be at the highest point along this line. Of course, that peak is influenced by a realization rate that is not known until after the close of the year and the mix of projects will cause the shape of this line to shift to some degree from year to year.

The table below details the results of this scenario using a 100% realization rate.

Table 1: Residual sub-TRC benefits across a range of energy simple paybacks

Energy SPB	Cumulative therm svgs	Cum therms as a % of 2011 portfolio	Aggregate sub-TRC B/C	Aggregate residual sub-TRC
1	103	0%	20.98	$ 435
2	24,866	3%	5.87	$ 136,127
3	249,715	31%	3.75	$ 1,140,764
4	303,007	37%	3.49	$ 1,349,136
5	380,417	47%	3.08	$ 1,642,548
6	426,302	53%	2.84	$ 1,807,886
7	439,831	54%	2.76	$ 1,838,113
8	489,116	60%	2.49	$ 1,952,089
9	537,315	66%	2.20	$ 1,950,420
10	635,501	78%	1.83	$ 1,917,669
11	641,748	79%	1.81	$ 1,901,841
12	644,370	80%	1.80	$ 1,895,407
13	661,828	82%	1.74	$ 1,869,945
14	665,834	82%	1.73	$ 1,858,466
15	668,983	83%	1.71	$ 1,844,284
16	669,680	83%	1.71	$ 1,840,121
17	672,988	83%	1.69	$ 1,828,220
18	672,988	83%	1.69	$ 1,828,220
19	678,849	84%	1.66	$ 1,795,468
20	692,146	85%	1.59	$ 1,709,976

This data does not incorporate any non-incentive utility costs that may be allocated to the program itself. To the extent that the sub-TRC value above is positive the project(s) can bear its customer incremental cost. However there are two cost categories not represented above; (1) the costs that are incremental to offering the site-specific program and (2) overall infrastructure costs that are allocated to the site-specific program. Though the overall infrastructure costs are unknown until the entire portfolio is optimized (which will be represented at a later point in this analysis), it is known that $406,000 of non-incentive utility costs are considered incremental to the site-specific program in the 2012 DSM Business Plan.

Inspection of this table demonstrates the sensitivity to the optimal level of energy simple payback for the program to the program realization rate. The following table summarizes some of these conclusions.

Table 2: TRC maximizing energy simple payback levels across various realization rates

Realization rate	Pgm. cost-effective[1]	Maximum[2]	13 yr vs Max[3]	13 yr pgm sub TRC[4]
100% realization rate	3 to 20+ years eSPB	8 years	96%	$1,464,335
80% realization rate	3 to 20+ years eSPB	8 years	76%	$586,147
60% realization rate	3 to 9 years eSPB	6 years	16%	$ (292,041)

1. This is the range of years of energy simple payback where the site-specific program would cover the customer incremental cost and non-incentive utility costs assigned to the program. These costs do not include non-incentive utility costs allocated at the overall program level.
2. This is the energy simple payback level that leads to the maximum residual sub-TRC.
3. This is the residual sub-TRC at a 13 year energy simple payback level as a percentage of the maximum energy simple payback. This indicates the degree of loss that is being incurred in residual sub-TRC as a consequence of not selecting the energy simple payback level which maximizes program sub-TRC performance.
4. This is the program sub-TRC, including non-incentive utility costs assigned to the program, at a 13 year energy simple payback. This does not include non-incentive utility costs that are assigned to the program.

The residual TRC benefits of the site-specific program is extraordinarily sensitive to the realization rate since that rate reduces TRC benefits but does not change TRC costs.

Though it is not possible to project realization rates for 2012, it is notable that the 2010 realization rate on the overall gas portfolio rose to 93% after several years of realization rates dwelling the 60% range. The 2010 realization rate on the site-specific portfolio is less predictable since this program is composed of unique projects that must be individually estimated, rather than relatively uniform projects were past experience can inform future estimates.

A review of 2011 year-to-date completions, which had no restriction upon project energy simple payback per the transition policy, indicates a wide diversity of paybacks. The previously described causes of deviation between the energy simple payback and TRC benefit to cost ratios (based on measure life and non-energy benefits) can be seen within this scattergram.

Figure 5: Site-specific projects (sub-TRC level vertically vs. energy simple payback, in months horizontally)

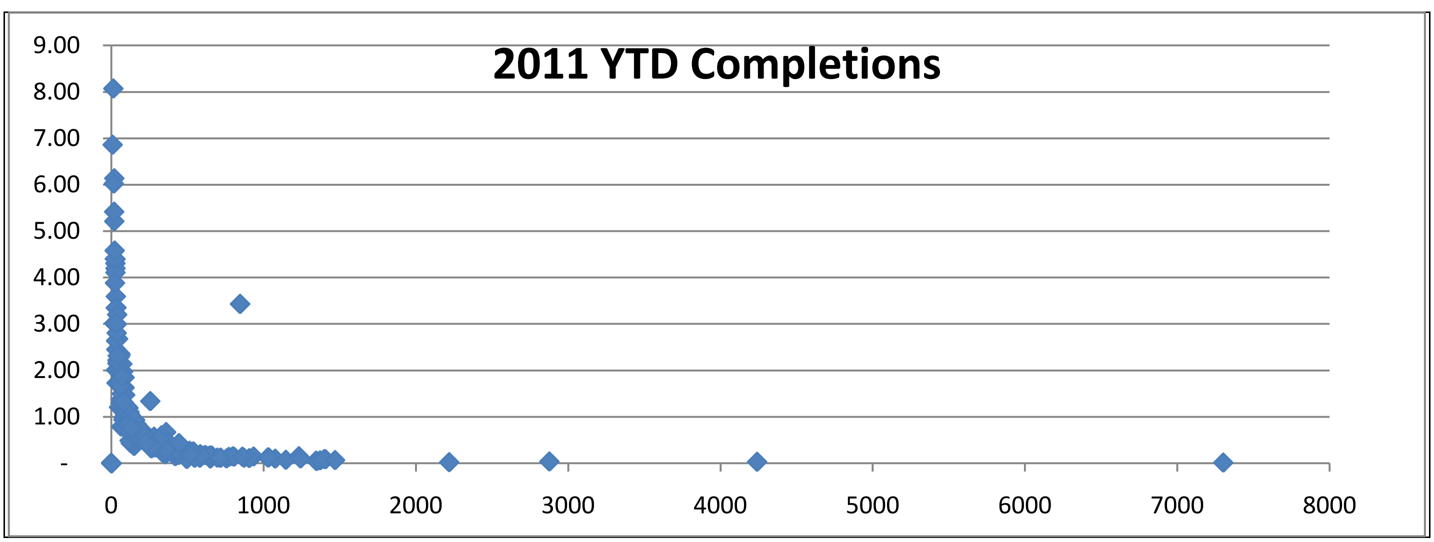
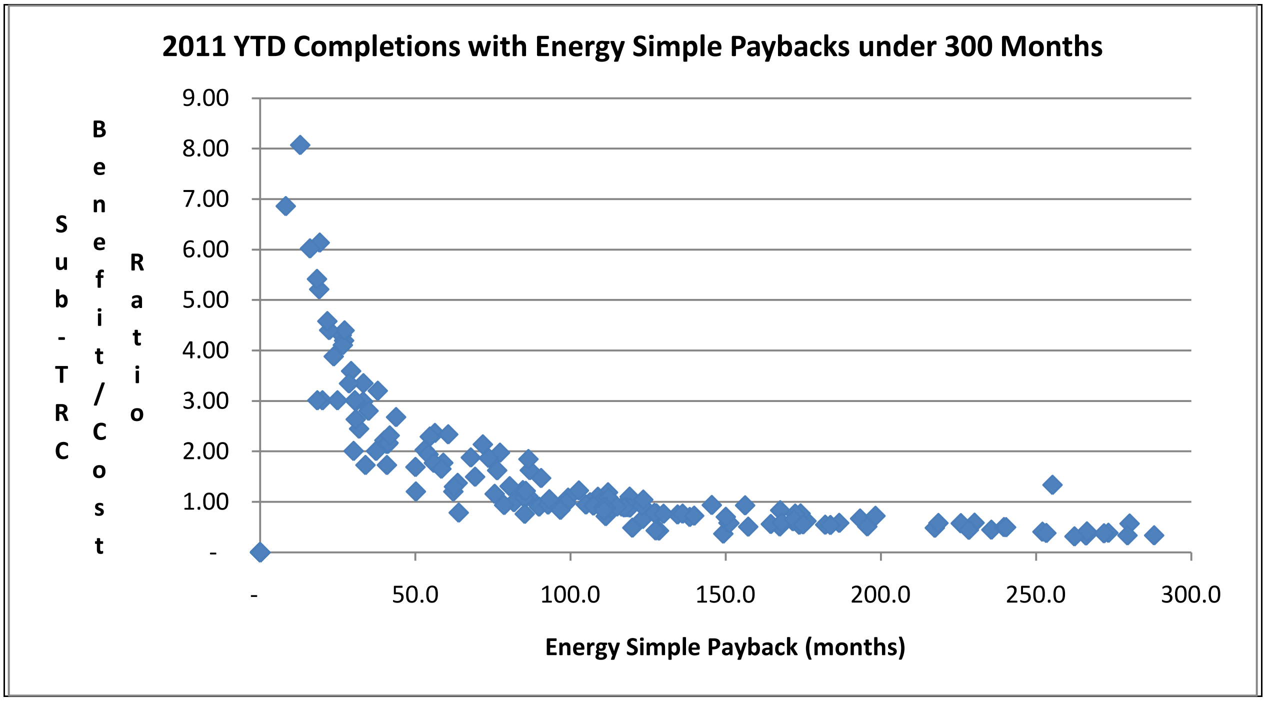


Figure 5 illustrates the quantity of very long payback projects. Of the 229 projects within this sample, only 115 (50%) were within the current 13 year energy simple payback. Ten percent of the projects had energy simple paybacks in excess of 66 years. A total of 76 projects (33% of the sample) were sub-TRC cost-effective.

Refining the chart to illustrate only the 67% of projects with energy simple paybacks of 300 months (25 years) or less leads to Figure 6 below.

Figure 6: Site-specific projects sub-TRC vs. energy simple payback



Based upon the 2011 projects, the longest energy simple payback of any sub-TRC cost-effective project is 123 months. The shortest energy simple payback of any non sub-TRC cost-effective project is 63 months with the exception of two projects with extraordinary non-energy benefits in the unverified data.

This project-by-project data is consistent with the residual sub-TRC data contained within Figure 4 and Tables 1 and 2. Reducing the energy simple payback for the site-specific program would enhance the sub-TRC results. However, the projects lying slightly beyond the optimal energy simple payback level identified within these illustrations have fairly little adverse affect upon the program (though that adverse impact does grow as realization rate falls). The result is a fairly large plateau where a sub-TRC value near the optimal level can be achieved based upon the use of the energy simple payback metric.

No recommendations are being made to pursue changes to the structure of the tariff, and specifically the use of energy simple payback as a metric for program eligibility or the level of energy simple payback required for participation in the program. The reasons for this endorsement of the current approach to the program are as follows:

1. Within approximately six months revised natural gas avoided costs will be available. The impact of those avoided costs will be essentially the same as the realization rate scenarios outlined previously; an 80% realization rate will have approximately the same impact as a 20% drop in the avoided costs. Given that the avoided cost is expected to fall significantly, any tariff revisions enacted now may need to be again revised in only six months. Any tightening of these provisions require the establishment of a policy for handling existing contractual obligations that is fairly complicated to communicate and administer. Based upon these factors, it

was concluded that the best course of action was to retain the existing structure, which has been found to be a good fit for the present and expected future, and to re-evaluate as necessary when actual avoided costs and final 2011 realization rates are available.

2. As part of the follow-up to the 2012 Natural Gas IRP the DSM team will evaluate the possibility of quantifying the value of risk reduction for inclusion within the avoided cost stream. A value for risk reduction currently appears within the electric avoided costs, though this is not the same type of risk that is under discussion for the natural gas portfolio. Any quantification of risk will act to increase the avoided cost level, offsetting the impact of lower avoided commodity cost and realization rates of less than 100%.
3. There is significant uncertainty around the likely realization rate. The increase in the portfolio realization rate coincided with changes in the Company's evaluation, measurement and verification responsibilities that may be more indicative of future realization rates than the longer five year history of realization rates. Though the unique nature of site-specific projects makes this experience less useful to improving estimates of energy savings (and therefore realization rates) it is expected that the site-specific program will experience some improvement in realization rate.
4. Based upon a 100% realization rate assumption, there is only a very minimal ($82,000) reduction in the program residual TRC value derived from applying the current 13 year energy simple payback vs. the TRC maximizing energy simple payback of eight years. This is only a 4% reduction in this residual value and is certainly insignificant given the total program costs and benefits.
    a. It is also recognized that these calculations should be considered to be underestimates of the true TRC value given that the non-energy impacts (which are disproportionately benefits) are often unquantifiable and therefore omitted from these calculations).

Despite the lack of recommendations for revisions to the tariff at this time, it is important to retain as much flexibility as possible for future management of the site-specific program. To retain that flexibility it is recommended that Account Executives, engineers and all customer contact employees should communicate to customers the current tariff and written transition policy as applicable, but also inform customers that (a) the Company is not obligated to any particular project until a contract is issued, (b) there is the prospect that the Company will revise the site-specific program during 2012, (c) the revisions will require regulatory approval and (d) they can work with their account executive to be on a list to keep up to date with any prospective changes in the program status if they so choose. Furthermore, Account Executives should maintain the list of customers with a known interest in the program composed of both those who have explicitly indicated their interest as well as those who are otherwise known to have a project that may be moving forward.

In the process of completing this analysis, the sensitivity to and importance of capturing quality data and using that information in a consistent manner to implement the site-specific program became clear. The following recommendation has been made to and accepted by the program implementation team:

> It is recommended that greater effort be focused upon the accuracy of the following inputs to the cost-effectiveness evaluation:
>
> - <u>Project costs</u>: Ensure that only the incremental project costs are being included and that those costs are symmetric with the assumptions being used to value the energy acquisition.
> - <u>Non-Energy Impacts</u>: All reasonable non-energy impacts should be identified and captured within the database. Those non-energy impacts that can be quantified with reasonable rigor and represented to a critical audience should be incorporated into the cost-effectiveness analysis.
> - <u>Measure Life</u>: Only measures with a life of ten years or greater are eligible for the site-specific program (per both current and proposed DSM tariffs).
> - <u>Jurisdiction and Rate</u>: The appropriate information should be captured for all projects. This includes both electric and natural gas rates for fuel-efficiency and dual-fuel projects.
> - <u>Dual-Fuel Incentive Calculator (DFIC) Version</u>: It would aid in the cost-effectiveness assessment and in intra-year quality control if the version of DFIC model used to calculate the incentive was captured

within SalesLogix. This version should be the one in place as of the date that project was contracted and should govern both the original contract as well as any contract revisions upon project completion.

- Pre-Project Review: Continue the current policy of performing an independent internal evaluation of all large projects and all projects with performance based contracts prior to the contracting of the project. Additionally, periodically during the year screen projects for errors and perform random reviews of projects not captured in the pre-contracting reviews above to determine the accuracy of the information used for program management purposes.

Inventory of site-specific contracts at year-end 2011

Based upon the analysis above and assuming that the portfolio of 2012 site-specific projects is similar to those observed in 2011; the projects complying with the current site-specific tariff are expected to be favorably contribute towards the natural gas DSM portfolio cost-effectiveness. These projects will cover all project-specific and program-specific TRC costs. It is uncertain at this point in the analysis if they will cover their allocated non-incentive utility costs.

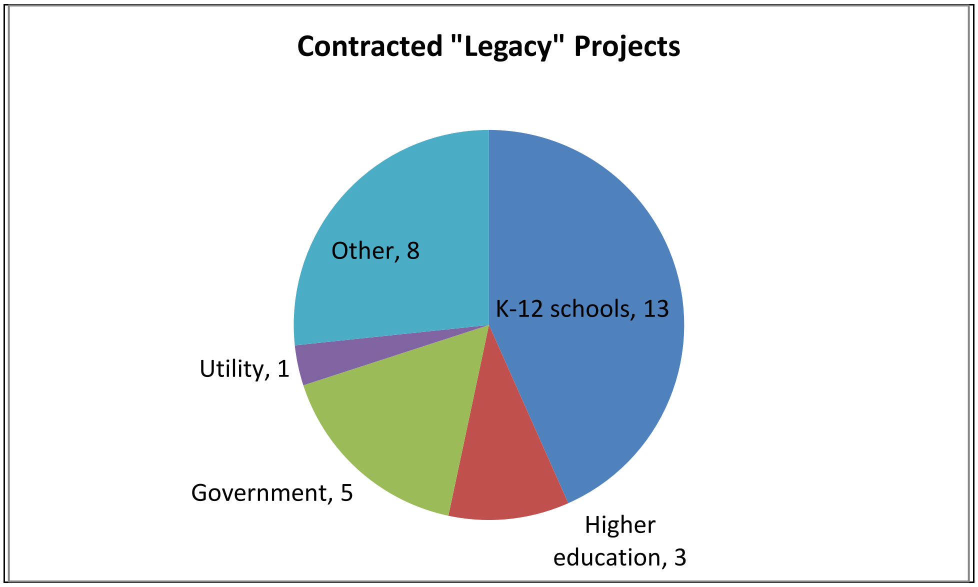
The ‘legacy’ projects eligible for completion during 2012, and a very few possibly extending to 2015, will continue to be a burden upon the program cost-effectiveness. These obligations are fixed obligations based upon contractual requirements and the transition policy that has been communicated to customers. The only remaining control that the Company has to manage these obligations is to encourage the careful administration of these policies in accordance with these commitments.

Though it is impossible to definitively answer the question of whether these ‘legacy’ projects will complete during 2012, all such projects should be known at this time given the transition policy requirement to contract these projects by April 30, 2011.

Of the 71 projects contracted at year-end 2011 with natural gas implications (either natural gas or dual-fuel efficiency projects), 63 projects had sufficient data within the SalesLogix database for analysis. Of these 63 projects, 33 projects (52%) were at or below the current 13 year energy simple payback requirement. This is comparable to the 50% (116 of 230) projects in the sample of completed 2011 projects. However, 2012 site-specific ‘legacy’ project completions will hopefully be diluted with additional projects qualifying under the current tariff that are contracted and completed during 2012. If 2012 saw 116 currently qualifying projects (the same as 2011) and all 30 of the ‘legacy’ projects completed, the projects over 13 year energy simple payback would be only 21% of the entire portfolio (less than half that observed in 2011).

A disaggregation of the remaining 30 ‘legacy’ projects is as follows:

Figure 7: Categorization of site-specific ‘legacy’ projects



Though there is no designation within the database to indicate if the project is eligible for completion in 2012 under the provisions of the transition policy, a brief inspection of the type of projects tends to indicate that many are likely to be permitted to complete in 2012 by the DSM Implementation team.

The 63 projects with usable data have an aggregate sub-TRC of a negative $2.46 million and a sub-TRC benefit-to-cost ratio of 0.62. Thus the entire mix of these projects, and not just those over the current 13 year energy simple payback maximum, would have an unfavorable impact upon the site-specific program. This impact would be even greater when site-specific assigned non-incentive utility cost and additional allocated non-incentive utility costs are added to the equation.

In aggregate, for the 33 contracted projects with usable data that qualify under the current 13 year energy simple payback tariff, the cumulative sub-TRC is a positive $0.88 million and the sub-TRC benefit-to-cost ratio is 1.72. These projects are bringing a favorable incremental impact to the cost-effectiveness of both the site-specific program and the overall natural gas DSM portfolio.

The breakout of cumulative sub-TRC vs. the energy simple payback looks very similar to what was seen for the 2011 completed projects. The two figures below illustrate the sub-TRC values at 100%, 80% and 60% realization rates. Figure 9 is a magnification of the projects with energy simple paybacks of less than 30 years that are also represented within Figure 8.

Figure 8: Cumulative sub-TRC across a range of energy simple paybacks, contracted projects

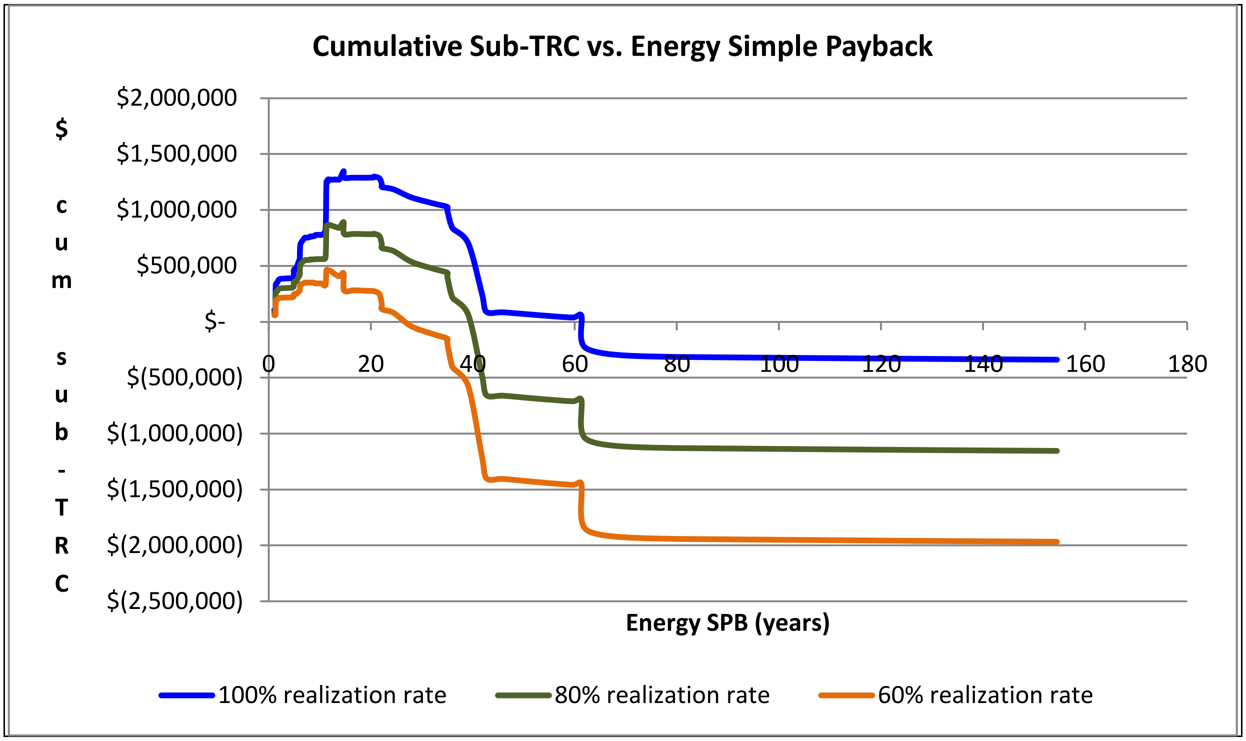
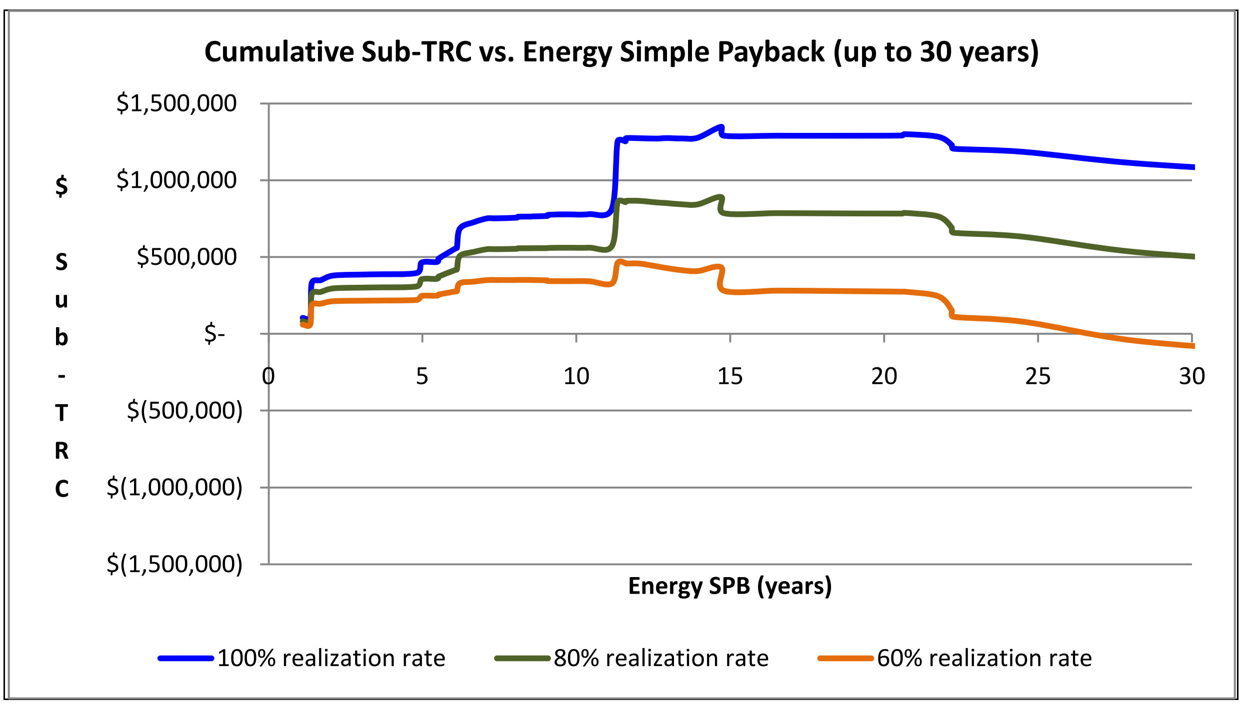


Figure 9: Cumulative sub-TRC across a range of energy simple paybacks, contracted projects (30 year paybacks or less)



Projection of the 2012 and 2013 site-specific program (including projected 2012 contracted projects)

With 100% or 80% realization rates, the maximum sub-TRC for these contracted projects is achieved at 14 years (for 100% and 80% realization) and 11 years (for 60% realization). The upper portion of this curve is fairly flat between 11 and 14 years leaving fairly little difference over this range of simple paybacks. This profile is more abrupt (or "lumpy") than the review of the 2011 portfolio because of the smaller number of projects. Absent particularly large projects occurring over this period of time a ten to 15 year range of energy simple paybacks seem to fit the optimization needs.

The potential for redesign of the site-specific program to improve cost-effectiveness has led to the conceptual proposal for revising the 50% ceiling on customer incentives as a percentage of customer incremental cost to a higher level, particularly for the most desirable (cost-effective) projects. This has the potential for enhancement of the throughput of cost-effective therms as well as the likelihood that net-to-gross impacts will be improved as well. The revision would require a modification to the existing DSM tariff. This possible redesign will remain under evaluation for possible consideration as part of the review of the gas portfolio after revised avoided costs are finalized and/or as part of the development of the 2013 DSM Business Plan.

There is little opportunity for management action beyond the previous recommendations. However, a revised projection of 2012 site-specific program cost-effectiveness based upon a presumed mix of 116 projects under 13 years energy simple payback and assuming the completion of all 30 contracted 'legacy' projects in 2012 would represent a more realistic projection. (It could be assumed that the eight contracted projects with insufficient data may be among those that would not complete, which would be a 79% completion rate for 'legacy' projects and projects with insufficient information).

The revised estimate of the 2012 site-specific program is based upon the following assumptions:

- The number of projects completed in 2012 will equal the number of qualifying (under 13 year energy simple payback) projects completed in 2011 (116 in total) plus the 'legacy' projects contracted at year-end 2011 (30 in total) for a total of 146 projects.
- The best projection of the cost-effectiveness of those projects is based upon
  - The actual data of the 33 year-end 2011 contracted qualifying projects with usable data
  - The actual data on the 30 year-end 2011 contracted 'legacy' projects with usable data
  - The remaining 83 qualifying projects will be based upon the average cost-effectiveness of the 2011 completed projects.

This leads to the TRC cost-effectiveness projection in Table 3 assuming 100%, 80% and 60% realization rates on the contracted estimate for energy savings.

Table 3: Summarization of the site-specific program under various realization rate scenarios

100%	realization rate				
	# projects	Sub-TRC benefits	Sub-TRC costs	Sub-TRC residual benefits	Sub TRC B/C
YE 2011 'legacy' projects	30	$ 1,955,389	$ 3,569,903	$ (1,614,515)	0.55
YE 2011 qualifying contracts	33	$ 2,115,273	$ 841,017	$ 1,274,256	2.52
Projected 2012 qualifying completes	83	$ 3,143,032	$ 1,805,050	$ 1,337,982	1.74
Expectation of 2012 project sub-TRC	146	$ 7,213,694	$ 6,215,970	$ 997,724	1.16
Assigned non-incentive utility costs			$ 457,683	$ (457,683)	-
Sub-TRC for overall site-sp program		$ 7,213,694	$ 6,673,653	$ 540,041	1.08

80%	realization rate				
	# projects	Sub-TRC benefits	Sub-TRC costs	Sub-TRC residual benefits	Sub TRC B/C
YE 2011 'legacy' projects	30	$ 1,564,311	$ 3,569,903	$ (2,005,592)	0.44
YE 2011 qualifying contracts	33	$ 1,692,382	$ 841,017	$ 851,364	2.01
Projected 2012 qualifying completes	83	$ 2,514,673	$ 1,805,050	$ 709,624	1.39
Expectation of 2012 project sub-TRC	146	$ 5,771,366	$ 6,215,970	$ (444,604)	0.93
Assigned non-incentive utility costs			$ 457,683	$ (457,683)	-
Sub-TRC for overall site-sp program		$ 5,771,366	$ 6,673,653	$ (902,287)	0.86

60%	realization rate				
	# projects	Sub-TRC benefits	Sub-TRC costs	Sub-TRC residual benefits	Sub TRC B/C
YE 2011 'legacy' projects	30	$ 1,173,233	$ 3,569,903	$ (2,396,670)	0.33
YE 2011 qualifying contracts	33	$ 1,269,490	$ 841,017	$ 428,472	1.51
Projected 2012 qualifying completes	83	$ 1,886,315	$ 1,805,050	$ 81,265	1.05
Expectation of 2012 project sub-TRC	146	$ 4,329,038	$ 6,215,970	$ (1,886,932)	0.70
Assigned non-incentive utility costs			$ 457,683	$ (457,683)	-
Sub-TRC for overall site-sp program		$ 4,329,038	$ 6,673,653	$ (2,344,615)	0.65

Notes:

1. The 116 qualifying (under 13 year energy simple payback) projects completed in 2011 were resized to represent the number of expected 2012 contracts that will complete in 2012.
2. The number of projects projected to be completed is the number of qualifying (under 13 year energy simple payback) projects from 2011 and the number of year-end 2011 ‘legacy’ projects with full data.

Based upon an interpolation of the above sensitivity analysis, a realization rate of about 93% is required for the full 2012 site-specific portfolio to be sub-TRC cost-effective at the program level (including the impact of contracted legacy projects). This calculation does not include any allocated non-incentive utility cost but does include all non-incentive utility cost assigned directly to the program.

Program performance in 2013 would be based entirely (or almost so) on projects meeting the current 13 year energy simple payback criteria.

Table 4: 2012 performance of non-legacy projects as a proxy for 2013 program performance

Non-legacy 2012 portfolio

2012 non-'legacy' projects	# projects	Sub-TRC benefits	Sub-TRC costs	Sub-TRC residual benefits	Sub TRC B/C
100% realization rate	116	$ 5,258,305	$ 2,646,067	$ 2,612,238	1.99
80% realization rate	116	$ 4,207,055	$ 2,646,067	$ 1,560,988	1.59
60% realization rate	116	$ 3,155,804	$ 2,646,067	$ 509,738	1.19

25% reduction in avoided costs for the non-legacy 2012 portfolio

2012 non-'legacy' projects	# projects	Sub-TRC benefits	Sub-TRC costs	Sub-TRC residual benefits	Sub TRC B/C
100% realization rate	116	$ 3,944,242	$ 2,646,067	$ 1,298,175	1.49
80% realization rate	116	$ 3,155,804	$ 2,646,067	$ 509,738	1.19
60% realization rate	116	$ 2,367,367	$ 2,646,067	$ (278,700)	0.89

Based upon the projections above, the site-specific program would be sub-TRC cost-effective in 2013 at projected avoided costs and a realization rate of only 67%. This not only represents a favorable outlook for the site-specific program, given the size of the program it promises to bring significant benefits to the overall natural gas DSM portfolio.

With the modifications to the site-specific program established as part of the January 1, 2011 revision to Avista's Schedule 190 tariff, the site-specific program is likely to be cost-effective once the existing 'legacy' project contractual obligations are cleared.

It should be noted that though the 13 year energy simple payback sacrifices little relative to the optimal program performance (and seems to be a reasonable accommodation of non-energy benefits not included within the energy simple payback), this does bear re-evaluation once the new avoided cost stream is firmly defined within the 2012 natural gas IRP. It is not necessarily certain that the avoided cost projections have been fully incorporated into the retail rates at any particular point due to timing differences between the two factors.

Hence it is recommended that a re-evaluation of the incentive tiers for the site-specific program should be completed if avoided costs materially change as a result of the 2012 natural gas IRP. The re-evaluation should consider differences in the avoided cost vs. retail rate relationship over the next three year period.

Prescriptive programs

Prescriptive programs have been developed to streamline the acquisition of efficiency measures that are relatively small in size, uniform in how they are applied and more predictable in their energy performance. These programs offer fixed incentives for measure installation, do not require contracts prior to purchase or installation of the equipment and allow the customer 90 days after purchase to submit rebate forms and related documentation.

Adopting a prescriptive approach to the promotion of an efficiency measure is a compromise between the accuracy and technical assistance that can be offered through an individualized treatment of each project vs. creating a program that is easier for customer to participate in, more amenable to utility or trade ally outreach efforts and suitable for more efficient program administration. Most of the programs that Avista offers through prescriptive approaches could not be economically offered through any other approach.

Though prescriptive approaches present challenges in obtaining baseline measurement, the general uniformity of the measures and similarity of the project population over time usually make it possible to apply past impact evaluations to estimates of future program performance with a reasonable degree of comfort. The exceptions occur when programs are significantly redesigned or new measures are offered.

Although measures offered through prescriptive programs don't have the long sales cycle that is generally observed with site-specific projects, prescriptive program offerings do require a notification period prior to making final program revisions. Generally the Company establishes a minimum of a 90 day notification period before program revisions are effective to permit customers who have purchased efficiency measures to submit their rebate forms. Preferably this notification period would be preceded with additional communications to trade allies. Thus there are inherent characteristics of prescriptive programs that limit the speed at which program revisions or terminations can occur. These timing issues have been incorporated into the projections of the 2012 and 2013 natural gas portfolio performance.

This optimization process has also taken the opportunity to update measure characteristics (costs, energy savings, non-energy benefits etc) based upon the preliminary results of the 2011 impact evaluations performed by the Cadmus Group.

This report characterizes the performance of measures based upon an annualized performance estimate as well as projecting 2012 and 2013 performance to include all program revisions or terminations. Influences of a measure upon companion measures (e.g. attic insulation influence upon the throughput of floor and wall insulation) have been considered as part of this analysis. Measure and program performance at current and projected avoided costs were taken into consideration.

The individual measures and programs will be separately evaluated for residential and non-residential prescriptive programs.

Residential prescriptive measures and programs

For all practical purposes it is accurate to say that the residential market is served essentially entirely through prescriptive programs. This optimization process began with the evaluation of eleven existing efficiency measures aggregated into five programs. One additional measure, low flow showerheads, has been launched since the conclusion of the 2012 DSM Business Plan. An additional three prospective measures were evaluated to determine if they were cost-effective acquisition opportunities.

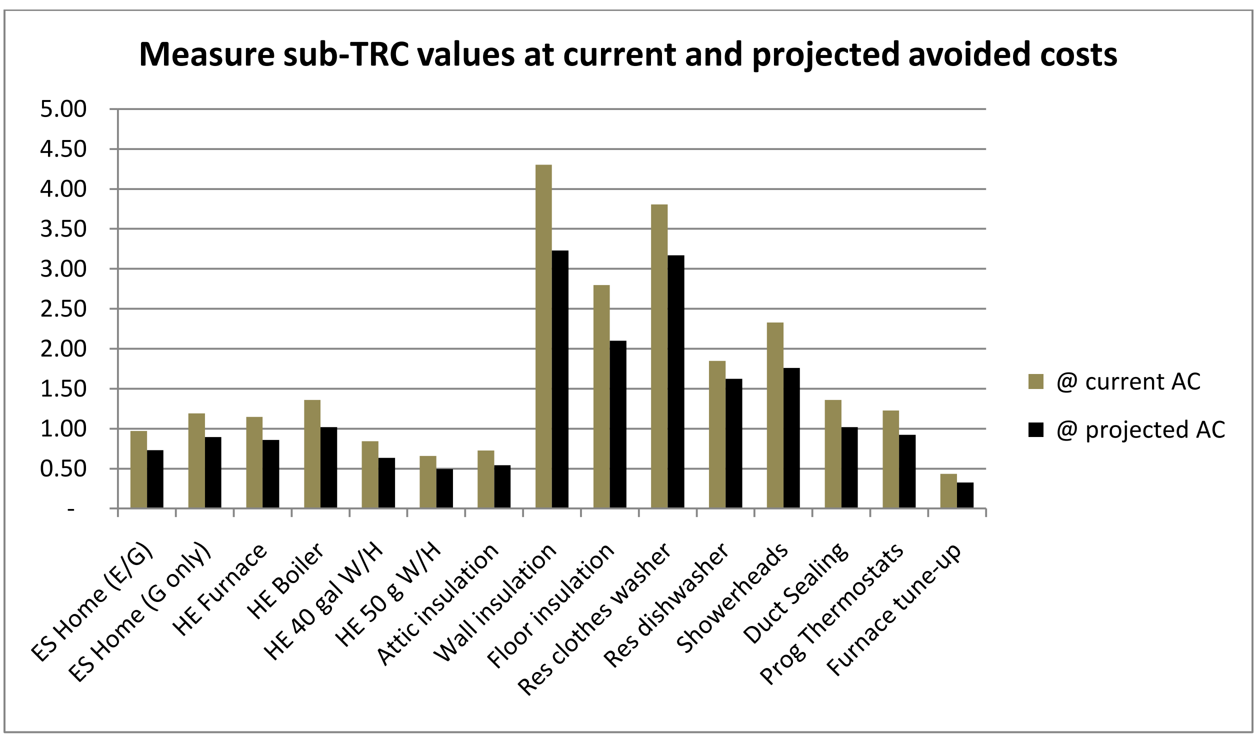
The 15 measures and their program affiliation are represented in Table 5 below.

Table 5: Natural gas efficiency measures

Measure	Program	Measure life	Cust Incr Cost $	Thm svgs/unit	kWh svgs/unit	Program therms	Net-to-gross ratio
ES Home (E/G)	ES Home	30	$ 3,000.00	197.00	1,068.00	21,276	74%
ES Home (G only)	ES Home	30	$ 1,500.00	197.00	-	2,955	74%
HE Furnace	HVAC	20	$ 700.00	104.00	-	304,824	61%
HE Boiler	HVAC	20	$ 800.00	141.00	-	6,063	61%
HE 40 gal W/H	Water heat	12	$ 50.00	8.20	-	738	52%
HE 50 g W/H	Water heat	12	$ 50.00	6.40	-	2,426	52%
Attic insulation	Insulation	20	$ 0.75	0.06	0.10	50,600	64%
Wall insulation	Insulation	20	$ 0.65	0.31	0.50	39,783	64%
Floor insulation	Insulation	20	$ 1.00	0.31	0.50	21,989	64%
Res clothes washer	Appliances	14	$ 33.00	14.80	-	26,152	35%
Res dishwasher	Appliances	9	$ 12.00	2.50	-	3,083	100%
Measures evaluated since the 2012 DSM Business Plan							
Showerheads	Water heat	5	$ 7.00	6.00	-	20,646	60%
Duct Sealing	Insulation	18	$ 500.00	93.20	-	93	64%
Prog Thermostats	HVAC	12	$ 125.00	27.00	-	27	60%
Furnace tune-up	HVAC	3	$ 120.00	25.00	-	25	60%

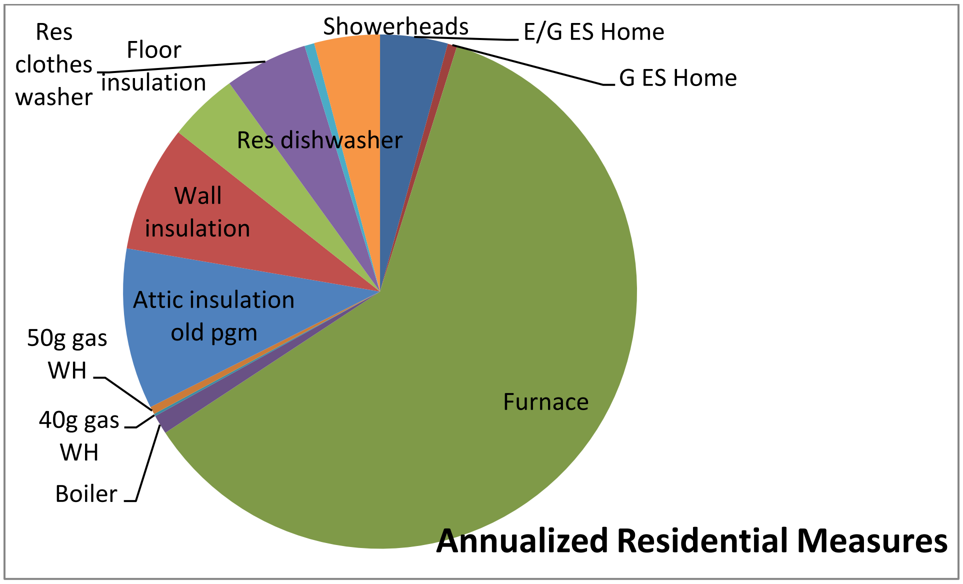
All measures, including both those offered and those under evaluation, were reviewed based upon the most current estimates of energy savings, non-energy benefits, useful life and incremental cost. Non-incentive utility costs were added in circumstances where there were costs directly related to the measure or program. Updated non-energy benefits, primarily water, sewer and related savings, were based upon recent resource cost surveys. The sub-TRC cost-effectiveness at the measure and program level is contained in the table below. These calculations include scenarios based upon both current and projected avoided costs.

Figure 10: Residential prescriptive performance by measure



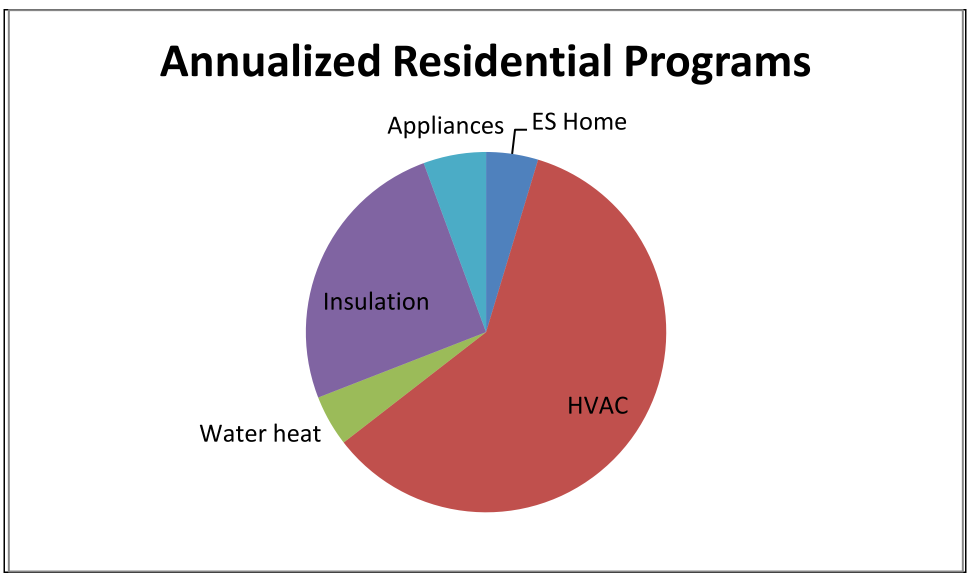
The annual therm acquisition of the pre-existing residential measures, if operated under proposed circumstances for a full year, is represented below. This distribution of therm acquisition is the starting point of the residential prescriptive program at the outset of the optimization process.

Figure 11: Residential prescriptive portfolio therm acquisition by measure



The following illustration summarizes how these eleven measures are aggregated into programs.

Figure 12: Residential prescriptive portfolio therm acquisition by program



This analysis led to the identification of three residential measures (attic insulation, 40 gallon water heaters and 50 gallon water heaters) that were not performing well from a cost-effectiveness perspective. The two water heater programs are small in acquisition (3,100 therms/year for the two measures together) and relatively small in the number of units (469) rebated per year. Attic insulation is a significantly more momentous program with 50,600 therms, and it is a closely related to a larger insulation program with a total of 112,400 therms of annual acquisition.

The following details led to recommendations and decisions for the two water heater and the attic insulation measures.

<u>40 gallon and 50 gallon water heaters:</u> These two measures are closely linked. Though the program participation and acquisition is not particularly significant, it does represent an important opportunity for many customers to benefit from the DSM portfolio. Both measures have sub-TRC values below 1.00 using current avoided costs and well below one using projected avoided costs. Based upon the assumptions used within this analysis there is little prospect that these measures will be cost-effective in the near future. Redesigns of these measure offerings were not sufficient to change the cost-effectiveness status.

It is worth noting that the impact evaluations that led to the estimates of 8.2 and 6.4 therms of annual energy savings, for the 40 and 50 gallon water heaters respectively, were based upon billing analysis. Since water heaters are relatively small components of the overall metered load, these estimates have a larger confidence interval around them than most other estimates used in this optimization process. However, the energy savings would require a 44% and 92% increase to reach cost-effective levels under current and projected avoided costs respectively. Increases in savings by this amount seem unlikely despite the confidence intervals surrounding the past impact evaluation. Nevertheless, the Cadmus Group will be delivering impact evaluations for the 2011 year in approximately May. In the unlikely event that those estimates are substantially higher it would be desirable to re-evaluate these two measures.

At this point it is recommended that the water heater programs be placed on a pathway towards termination. Program managers have done so, and also established a timeline for the eventual termination that will allow for a modification to that direction in the event new impact evaluation leads to much higher energy savings estimates.

Communication of the termination of these two measures is scheduled for August 31st, 2012 with rebates accepted for 90 days after that time. This will allow time for the Cadmus Group impact evaluations to be received and reviewed.

<u>Attic insulation</u>: The attic insulation measure is closely linked to the wall and floor insulation programs. Insulation has long been one of the core residential measures. Recently the program was revised to eliminate “do-it-yourself” installations based upon process and impact evaluation results.

The program currently requires the addition of at least R-10 to homes with pre-existing levels of insulation at R-19 or less. Typically customers add more than the minimum level of insulation to the home. Both the costs and benefits of the actual program history are reflected within this analysis.

The most recent impact evaluations indicate savings of only 0.06 therms per square foot. This leads to a sub-TRC of 0.73 under current avoided cost and 0.54 under projected avoided cost. Thus savings would have to increase by 38% to 84% to be cost-effective under these two avoided cost scenarios without any change in customer incremental cost or non-utility incentive cost.

It has been recommended that the program be placed on a pathway towards termination. Program managers have done so. The current schedule calls for the termination to be communicated on August 31st, 2012 with rebates accepted for 90 days after that date.

This timetable does allow for the opportunity for program managers to explore the possibility of redesigning the program to meet cost-effectiveness requirements. This redesign would most likely involve establishing a lower maximum level of pre-existing insulation within the home, perhaps R-10 instead of R-19, with the intent of obtaining greater savings from the addition of the same amount of insulation (and thus the same customer cost). If the savings can be substantially increased without additional cost, a redesign rather than a termination of this measure may be in order.

If the program redesign cannot be successful without pre-inspection of the home, and the non-incentive utility cost related to that implementation effort, then it is unlikely that a redesign would be cost-effective. Under any circumstances, establishing substantially lower levels of maximum pre-existing insulation as a requirement for program eligibility will significantly reduce the number of customer participants and therefore program acquisition.

It is also recognized that reducing attic insulation throughput will adversely impact the cost-effective wall and floor insulation measures. Various scenarios of the relationship between these three measures were evaluated, such as recognizing that terminating attic insulation may reduce floor and wall insulation acquisition by 25%, but none were of these scenarios were found to justify the cost-effective continuation of the attic measure.

Based upon in-progress analysis completed as part of the 2012 Natural Gas Conservation Potential Assessment (CPA) and additional work performed within Avista, four measures have been identified for additional review as part of this optimization process. These measures and their status are discussed below.

<u>Low-flow showerheads</u>: Avista's continued participation in the Simple Steps, Smart Savings program (a regional program of manufacturer buy-downs of compact fluorescent lamps) includes the option of adding low-flow showerheads to that package of measures.

Avista's evaluation of the cost-effectiveness of the measure based upon the cost of the physical showerhead and the administrative cost of the measure indicated a 2.33 sub-TRC under current avoided cost (and a 1.76 sub-TRC with proposed avoided costs). Though the energy savings was not based upon Avista impact evaluation, since this program has no history with Avista, the 6 therms/unit estimate of savings was derived from estimates made by the Company's third-party evaluator (Cadmus), and this amount is considerably lower than the 12 therms per unit estimate derived from the coordinators of the regional program.

<u>Duct Insulation</u>: Early within the process this measure was evaluated and rejected based upon a marginal 0.94 sub-TRC at current avoided costs and 0.71 with projected avoided cost. Reconsideration of the measure based upon a revised assumption of measure life (10 years to 18 years) per the Global CPA study improved the cost-effectiveness to 1.36 and 1.02 at current and proposed avoided costs respectively.

Given the marginal cost-effectiveness at projected avoided cost levels and the reluctance to offer a measure that may need to terminate once revised avoided costs are known, it was recommended that this measure be placed on hold and re-evaluated as part of the 2013 DSM Business Plan. Program managers have no plans on launching this measure in the foreseeable future, consistent with this recommendation.

This measure will not be included in the projected 2012 and 2013 portfolios within this optimization process.

<u>Programmable thermostats</u>: This measure has been offered as part of the Avista gas portfolio in the past but was discontinued over concerns that behavioral impact of the program substantially (perhaps fully or even more than fully) offset the energy savings from the measure. The discontinuation was based upon the plausible point of view that customers may use programmable thermostats to increase the thermostat setting prior to the time that they would do so with a manual thermostat. It is also recognized that this 'take-back' may also be considered a non-energy benefit, though the Company has not proposed to quantify that value. Additionally programmable thermostats are becoming increasingly common in Avista's Washington / Idaho service territory, bringing into question whether manual thermostats are an appropriate base case assumption.

Evaluation of the measure presuming 27 therms of annual savings lead to a sub-TRC cost-effectiveness of 1.23 (0.92 using proposed avoided costs). Thus even at a level of savings that does not incorporate behavioral aspects the measure would be expected to become mildly cost-ineffective.

Based upon the marginal cost-effectiveness under projected avoided costs and the likely impact of behavior upon metered energy savings, it was recommended that this measure be withheld. Program managers are not planning on taking any steps to offer this measure, and it is not included in the 2012 and 2013 portfolios within this optimization process.

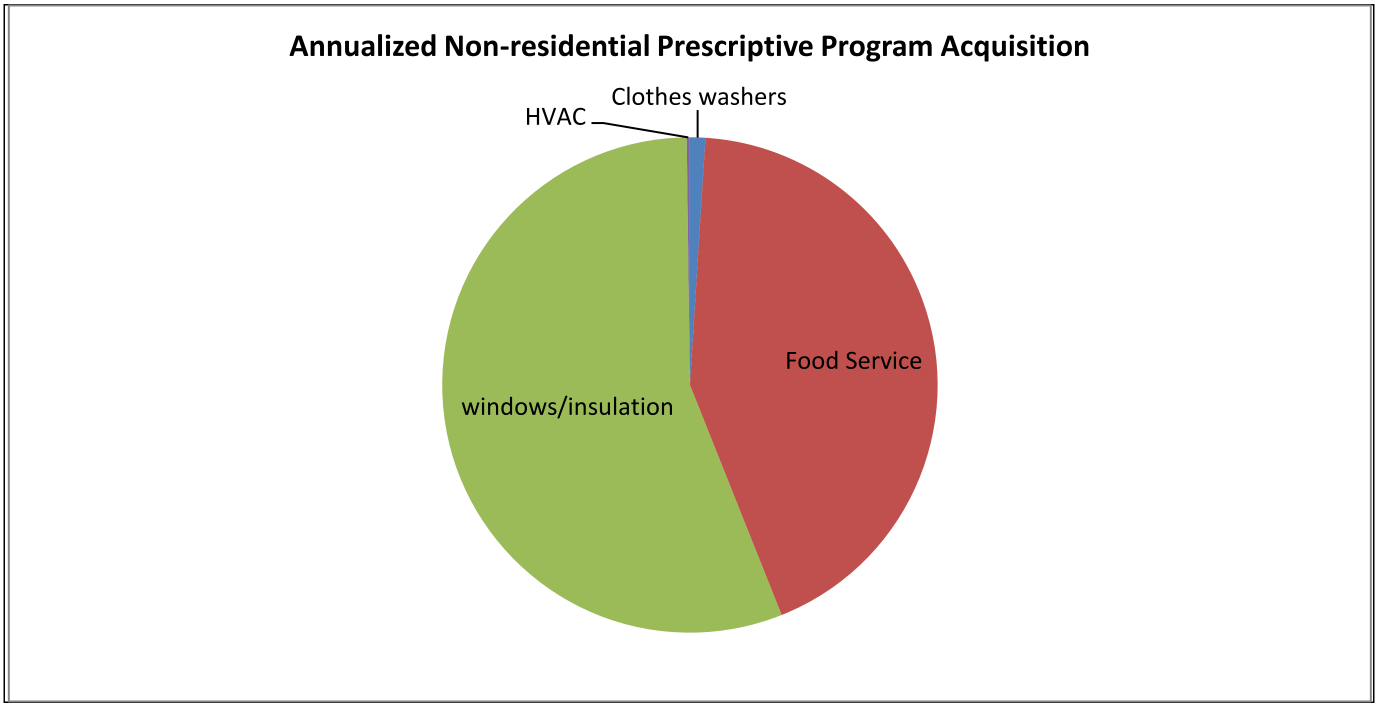
Boiler tune-up: The boiler tune-up program developed for review was based upon a standardized professional 10-point tune-up of residential boilers to include measurement of combustion efficiency, adjustment of airflow and gas input, cleaning of burners and burner nozzles, physical inspections and safety checks. The program was oriented towards a market of boilers that were at least two years old and at least 100kBtu.

As so designed, the program was expected to yield 25 therms in annual energy savings for a three year period at a cost of $120. The sub-TRC cost-effectiveness of this measure at current avoided costs was 0.43, well short of what would be necessary to justify the program as part of the gas portfolio. Consequently it is recommended that this measure be withheld. Program managers have no plans on further developing or launching this measure.

Non-Residential Prescriptive Measures and Programs

The pre-existing non-residential prescriptive portfolio encompasses 55 measures organized into four programs. The proliferation of measures is largely the result of a substantial number of food service measures (31 in total) with a potential gas application organized into a larger combined fuel food service program. Additionally the application of the same physical clothes washer in different permutations of electric or gas water heat or dryer applications create 12 measures out of four physical pieces of equipment. Many of these individual measures deliver a very small annual therm acquisition. Overall the portfolio acquisition has been heavily dominated by shell (windows and insulation) and food service measures.

Figure 13: Non-residential therm acquisition by program



No additional measures beyond those currently within the portfolio were evaluated.

A tabular overview of the non-residential portfolio is represented in Table 6 below.

Table 6: Pre-existing non-residential measures

Measure	Program	life	Cust incr cost $	Therm svgs/unit	kWh svgs/unit	therms	NTG ratio
ES fryer	Food Service	10	2,500.00	505	-	1,010	87%
ES 3 pan cooker	Food Service	10	1,867.00	1,042	-	1,042	87%
ES 4 pan cooker	Food Service	10	2,489.00	1,389	-	1,389	87%
ES 5 pan cooker	Food Service	10	3,111.00	1,737	-	1,737	87%
ES 6 pan cooker	Food Service	10	3,733.00	2,084	-	4,168	87%
Vent hood VSC	Food Service	10	1,297.60	293	-	2,049	87%
Vent hood VSC w make-up air	Food Service	10	3,000.00	500	-	3,500	87%
HE convection oven	Food Service	10	1,886.00	323	-	4,199	87%
HE combination oven	Food Service	10	5,717.00	403	-	806	87%
HE rack oven	Food Service	10	4,933.00	1,034	-	2,068	87%
HE griddle	Food Service	10	491.00	88	-	176	87%
ES under counter DW [4]	Food Service	10	1,000.00	55	-	-	87%
ES under counter DW [5]	Food Service	10	1,000.00	217	2,680	217	87%
ES door type DW[4]	Food Service	10	2,000.00	554	-	1,109	87%
ES door type DW [5]	Food Service	10	2,100.00	405	5,197	811	87%
ES single tank DW [4]	Food Service	10	3,000.00	520	-	1,040	87%
ES single tank DW [5]	Food Service	10	3,000.00	508	7,998	1,017	87%
ES multi tank DW [4]	Food Service	10	4,000.00	798	-	1,596	87%
ES multi tank DW [5]	Food Service	10	4,000.00	993	12,249	1,986	87%
ES under counter DW [7]	Food Service	10	1,000.00	109	4,689	217	87%
ES door type DW [7]	Food Service	10	2,100.00	203	8,948	405	87%
ES single tank DW [7]	Food Service	10	3,000.00	254	12,701	508	87%
ES multi tank DW [7]	Food Service	10	4,000.00	496	21,436	993	87%
ES under counter DW [7]	Food Service	10	1,000.00	55	-	-	87%
ES under counter DW [8]	Food Service	10	1,000.00	326	-	652	87%
ES door type DW [7]	Food Service	10	2,000.00	554	-	1,109	87%
ES door type DW [8]	Food Service	10	2,100.00	608	195	1,216	87%
ES single tank DW [7]	Food Service	10	3,000.00	520	-	1,040	87%
ES single tank DW [8]	Food Service	10	3,000.00	762	1,728	1,525	87%
ES multi tank DW [7]	Food Service	10	4,000.00	798	-	1,596	87%
ES multi tank DW [8]	Food Service	10	4,000.00	1,489	-	2,979	87%
HE furnace	HVAC	20	6.66	2.91	-	102	87%
Super HE furnace	HVAC	20	8.61	3.71	-	74	87%
HE boiler	HVAC	20	12.31	1.25	-	4	87%
Super HE boiler	HVAC	20	14.77	2.36	-	12	87%
HE unit heater	HVAC	20	12.00	1.65	-	8	87%
Wall R4-R18-	windows/insulation	25	0.61	0.31	0.50	8,250	87%
Wall R4 - R19+	windows/insulation	25	0.65	0.36	0.39	7,693	87%
Attic R11 - R44-	windows/insulation	25	0.76	0.10	0.15	2,421	87%
Attic R11-R45+	windows/insulation	25	0.86	0.13	0.13	1,300	87%
Roof R11-R30+	windows/insulation	25	0.62	0.12	0.13	24,071	87%
New windows	windows/insulation	20	2.25	0.74	0.10	3,700	87%
Retro windows	windows/insulation	20	19.00	0.46	8.15	7,360	87%
ES CW [1]	Clothes washers	7	370.00	13.51	629	-	87%
CEE Tier 1 [1]	Clothes washers	7	370.00	13.51	629	14	87%
CEE Tier 2 [1]	Clothes washers	7	1,120.00	16.66	776	33	87%
CEE Tier 3 [1]	Clothes washers	7	1,420.00	19.23	896	38	87%
ES CW [2]	Clothes washers	7	370.00	11.62	610	174	87%
CEE Tier 1 [2]	Clothes washers	7	370.00	11.62	610	12	87%
CEE Tier 2 [2]	Clothes washers	7	1,120.00	14.33	752	29	87%
CEE Tier 3 [2]	Clothes washers	7	1,420.00	16.55	869	33	87%
ES CW [3]	Clothes washers	7	370.00	25.12	214	126	87%
CEE Tier 1 [3]	Clothes washers	7	370.00	25.12	214	25	87%
CEE Tier 2 [3]	Clothes washers	7	1,120.00	30.99	264	465	87%
CEE Tier 3 [3]	Clothes washers	7	1,420.00	35.78	305	36	87%

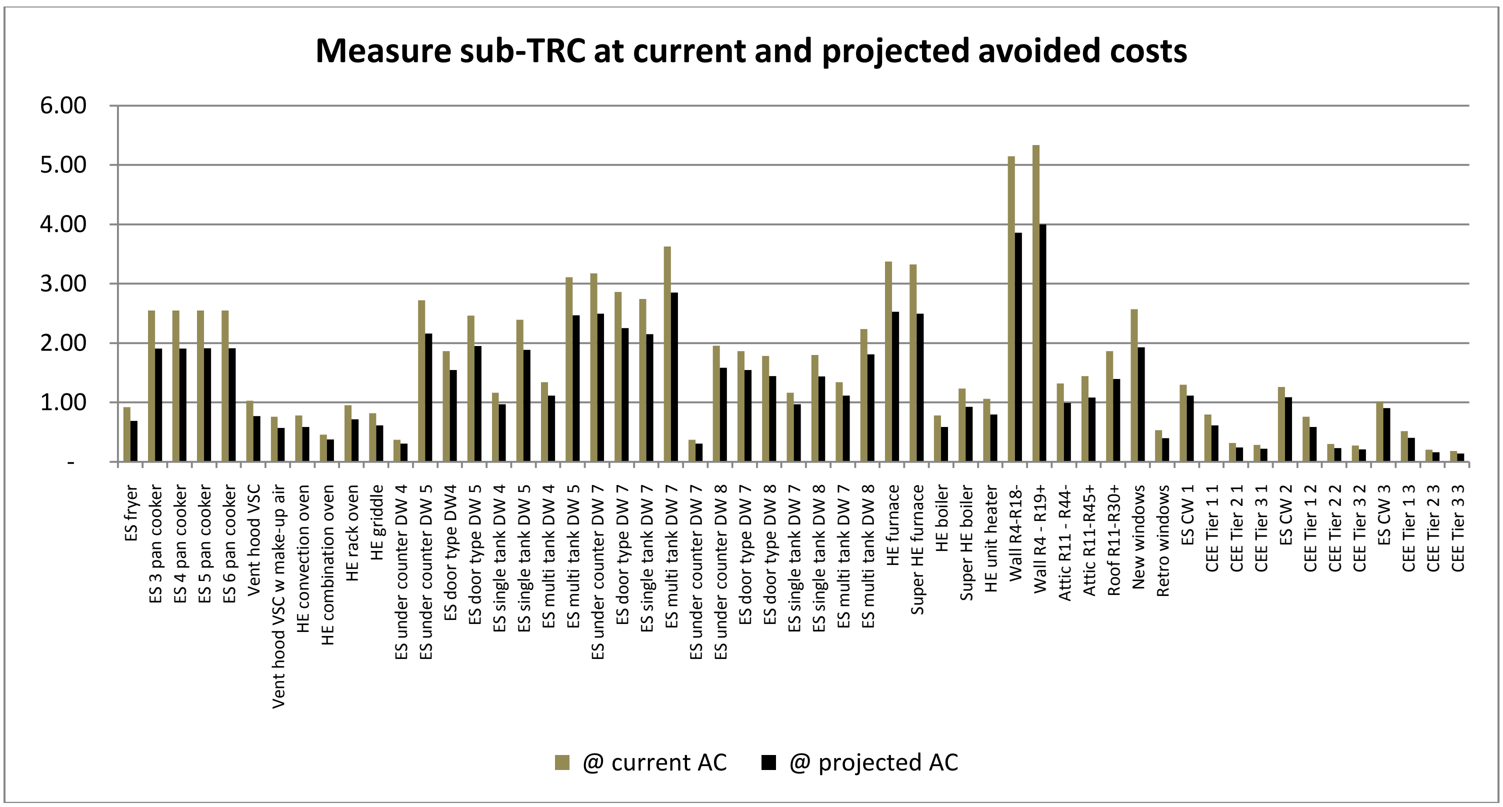
Non-residential measures which are terminated from prescriptive program offerings remain eligible for incentives under the site-specific program if they otherwise qualify. Qualifying as a site-specific project does require a measure life of ten years or more and an energy simple payback of 13 years or less.

In 2011 several categories of measures were terminated as prescriptive programs (and generally transferred to the site-specific program) as part of a streamlining of the portfolio based upon third-party evaluation recommendations. These terminated prescriptive measures included:

a. Prescriptive Refrigerated Warehouse Program
b. Prescriptive Demand-Controlled Ventilation Program
c. Prescriptive Open Loop Chiller/Cooling Tower Side-Stream Filtration Program
d. Prescriptive Steam Trap Replacement or Repair Program
e. Prescriptive Vending Machine Controls

The results of the cost-effectiveness analysis of currently offered measures based upon the most recent energy savings (generally contained within the TRM) as well as cost, non-energy and measure life assumptions are summarized below. These calculations include a scenario based upon projected avoided cost from current levels.

Figure 14: Non-residential prescriptive measure performance



Notes related to the above measure types:

1. Electric hot water, gas dryer
2. Gas hot water, electric dryer
3. Gas hot water, gas dryer
4. Low temp, gas water, electric booster
5. High temp, gas water, electric booster
6. High temp, electric water, gas booster
7. Low temp, gas water and booster
8. High temp, gas water and booster

CW = Clothes washer
DW = Dishwasher

Review of the analysis and discussion with program managers indicated that a total of 12 measures were in need of immediate attention as part of the gas portfolio optimization and an additional five measures were identified as a lower priority for current review but likely to require action based upon projected avoided costs. The issues, recommendation and decisions surrounding these measures are categorized by program below.

Food Service Measures

Two oven measures were identified for immediate attention and an additional five food service program measures were identified for a lower priority review. All of these measures failed to meet cost-effectiveness criteria based upon projected avoided costs, and all but one failed at current avoided cost.

The initial recommendation was for termination of the two oven measures and the plan for an immediate review of the other measures once new avoided cost streams are available. There was a very high probability that these additional five measures would be recommended for termination as a result of that future evaluation.

Program managers indicated a strong desire to deliver one communication for all of these measures rather than execute a termination of two measures in the near-term and another five measures on a timetable only a few months different. Consequently all seven measures have been place upon a schedule for termination. The scheduled notification of the termination of these measures is August 31st, 2012 with the last rebates accepted 90 days after that date.

Clothes Washers

Avista currently offers incentives for three different levels of equipment efficiency (CEE levels tier 1, 2 and 3) when installed in non-residential applications. Additionally Avista occasionally receives residential rebate forms for Energy Star clothes washers that were installed in non-residential applications. These four basic equipment types create 12 separable measures based upon the potential energy sources used for water heating and dryers.

Three of these four equipment types (all tier levels of the CEE units) are cost-ineffective at both existing and projected levels of avoided cost. The residential Energy Star units installed in non-residential applications are cost-effective.

Based upon the cost-effectiveness of these measures and the unlikelihood of improvement of that cost-effectiveness through program redesign, it was recommended that all three of the CEE tier washing machines be scheduled for termination.

The Company is proceeding with the termination of all three of the CEE clothes washers in all applications (nine measures in total) with a scheduled communication of August 31st of this year with rebates accepted for 90 days after that date. The Company will continue to accept residential rebates for Energy Star clothes washers installed in non-residential applications using the publicized residential rebate. The existing allowance for the infrequent error of submitting a residential rebate for appliances installed in non-residential applications will continue to apply.

Window and Insulation measures

The Company offers prescriptive programs for the installation of windows in both new and retrofit applications. The different base case assumptions for these two measures create substantial differences in the valuations of energy savings and incremental cost. The higher incremental cost of replacing existing functional windows lead to this program being cost-ineffective at both existing and projected avoided costs.

There linkage between the cost-ineffective natural gas retrofit window program and the cost-effective natural gas new window program, as well as the electric companions to this program that were not evaluated as part of this optimization process, were not deemed to be sufficiently strong to warrant the continuation of the measure.

It was recommended that the retrofit window measure be scheduled for termination. The program managers are applying the same August 31st, 2012 date for communication of this termination with rebates accepted up to 90 days after that date.

Regional Market Transformation

Avista is one of several natural gas utilities working with the Northwest Energy Efficiency Alliance (NEEA) to develop a portfolio of market transformation ventures similar to and building off of their successful 15 year experience in transforming similar electric markets. Avista's criteria for participation within this portfolio are that the effort must be cost-effective and superior to any mutually exclusive approaches to achieving the desire efficiency objectives. Additional issues, such as geographic and funding equity within the region, will also be strongly considered as part of Avista's prospective participation.

To date NEEA has obtained sufficient funding from natural gas utilities to investigate the development of several prospective natural gas efficiency measures with market transformation potential. These measures remain under consideration, with expected revisions in recognition of changing avoided costs.

Avista 2012 DSM Business Plan budgeted $146,000 for this activity during that year. This investment is not expected to yield quantifiable benefits during that year, and is not expected to yield significant quantifiable benefits in 2013. By the very nature of market transformation ventures there is a significant lag between the timing of the investment and the realization of benefits.

For reasons of this timing issue and because Avista's consideration of participation in future regional natural gas market transformation is separable from the local portfolio of programs, this optimization process has focused upon the local portfolio only.

It is worth noting that NEEA's activities within electric market has successfully accelerated and enhanced the commercial availability of efficiency measures. This improves the options that local utilities have available to them when they are building local energy efficiency portfolios. Historically it has been Avista's observation that market transformation is most successful in markets characterized by large numbers of small customers; predominantly residential and to a lesser extent small commercial markets. It is Avista's hope for the future that a healthy NEEA natural gas market transformation portfolio will move efficiency measures towards commercialization and therefore provide the utility with a broader range of options for building effective a cost-effective local portfolio. As avoided costs make the cost-effectiveness of efficiency programs a more difficult challenge, the regional market transformation tool may be what is necessary to continue to deliver a cost-effective local portfolio.

Final Allocation of Non-Incentive Utility Costs

Up to this point in the portfolio optimization process, only those non-incentive utility costs that were incremental at the measure level have been included within the analysis. The majority of the these other local non-incentive utility costs, such as labor, CPA and EM&V costs, are not recognized at the measure level. These costs are allocated at the program and portfolio level of aggregation.

Ultimately all local costs are recognized within the portfolio calculation of cost-effectiveness. By recognizing the costs at the level of aggregation at which the cost is incremental the Company avoids erroneously eliminating a measure or program from the portfolio in the belief that it is non-cost-effective when in fact it would have favorably contributed to the overall portfolio cost-effectiveness.

Generally speaking, third-party program administration costs are assigned at the measure level of aggregation, labor is assigned at the program level and other costs unrelated to specific programs (CPA, EM&V etc) are assigned at the portfolio level.

Joint costs shared by both the electric and natural gas portfolios are allocated based upon the avoided cost of energy associated with those programs. The allocations borne by the natural gas portfolio decline as measures or programs are terminated (and increase for additions). Thus the total non-incentive utility cost changes over the 2012 and 2013 periods due to program terminations and launches.

Table 7 below summarizes the non-incentive utility costs for annualized programs (the expected 2012 operations absent any revisions occurring as part of this portfolio optimization) as well as 2012 and 2013 costs based upon expected revisions to the program.

Table 7: Summary of assignment and allocation of non-incentive utility costs at the program and portfolio level

Summary of Non-Incentive Utility Costs (NIUC) Assigned or Allocated to Programs or the Portfolio		
NIUC assigned at the program level (based upon pre-existing annualized programs)		
$	89,250	Site-specific (Legacy)
$	226,875	Site-specific (Qualifying)
$	218	Non-res Psc clothes washers
$	11,982	Non-res Psc food service
$	28,752	Non-res Psc windows/insulation
$	96	Non-res Psc non-res HVAC
$	18,251	Res Psc ES home
$	199,133	Res Psc res HVAC
$	6,120	Res Psc water heat
$	84,132	Res Psc insulation
$	13,428	Res Psc appliance
$	678,235	Labor to be assigned at program level based upon annualized programs
NIUC assigned to natural gas		
$	2,500	NIUC assigned to EM&V equipment (the gas share only)
$	150,000	NIUC assigned to the gas CPA
$	80,607	NIUC assigned to general EM&V (gas share only)
$	177,042	NIUC assigned to regulatory and other PPA functions (gas share only)
$	470,057	NIUC assigned to gas programs (excluding site-specific)
$	880,206	
NIUC allocated to the natural gas portfolio		
$	319,143	Original gas share of joint NIUC
$	313,644	Revised 2012 gas share of joint NIUC
$	220,791	Revised 2013 gas share of joint NIUC

These costs, modified as necessary to reflect planned changes in the measures and programs, are advanced to the calculation of portfolio cost-effectiveness.

Portfolio Cost-Effectiveness

Having established an expectation for the revised 2012 and 2013 programs, calculated the TRC benefits and costs occurring at the measure level, and then collected and allocated all other non-incentive utility costs at the program and portfolio level, it is possible to estimate the cost-effectiveness of the overall portfolio.

The approach that has been taken to this optimization is to build measures that are cost-effective based upon their incremental benefits and costs into programs (which are burdened with additional costs, primarily labor) and ultimately to the portfolio (which are burdened with additional costs, primarily the CPA and EM&V). For the portfolio to perform well, each successive level of categorization must not only bear the costs immediately associated with that measure or program, there must be sufficient residual benefits to offset the non-incentive costs that will be recognized at the next level of aggregation. With the increased costs associated with resource planning and evaluation functions recognized at the portfolio level, it is increasingly possible to build a collection of incrementally cost-effective measures into a portfolio that cannot fully offset these overhead costs. Additionally, the projected lower avoided cost reduces the number of measures and programs that are cost-effective and it reduces the residual benefit of those programs that are cost-effective.

This portfolio analysis is based upon the use of current avoided cost for calendar year 2012 and projected avoided cost for 2013. Despite the use of substantially lower avoided costs in 2013, the portfolio cost-effectiveness improves as a result of the termination of cost-ineffective programs planned in 2012, the launch of one cost-effective measure and the expiration or completion of the vast majority of site-specific legacy projects.

Figure 15 below graphically depicts the cost-effectiveness of the total portfolio for calendar year 2012 and 2013. The illustration also reflects the sensitivity of the portfolio cost-effectiveness to variations in the realization rate of the site-specific program (holding the realization rate of prescriptive programs to an assumed 100% level). It is expected that the realization rate of the prescriptive programs is at relatively little uncertainty given the availability of historical impact evaluations. The site-specific portfolio is composed of individual projects each of which are unique and therefore subject to greater uncertainty.

Figure 15: Portfolio Cost-Effectiveness

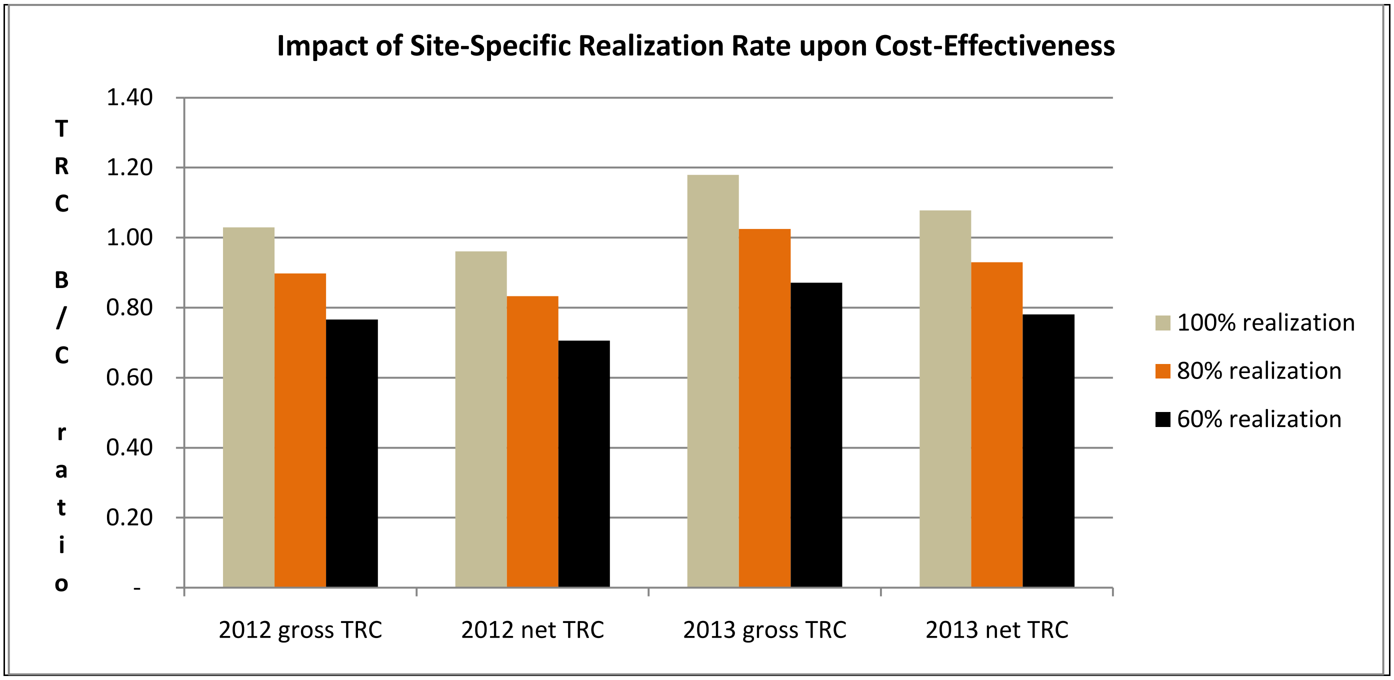


Figure 15 notes:

- Based upon net and gross acquisition.
- Using current avoided costs for 2012 and projected avoided costs for 2013.
- Assuming 100% realization for prescriptive programs and the specified realization rate for site-specific programs.

A site-specific program realization rate of 77% is necessary to deliver a cost-effective portfolio on a gross basis in 2013, assuming that the prescriptive program realization rate is 100%. A similar break-even analysis on the 2013 net portfolio indicates that a 90% site-specific realization rate would be necessary for the portfolio to be cost-effective. All of these assumptions are within the range of reason, particularly given the opportunity for additional program optimizations to occur as part of the 2013 DSM Business Plan.

Tables 8, 9, 10 and 11 below provide further details on non-incentive utility costs, and program and portfolio performance.

Table 8: 2012 Natural Gas Local Portfolio (gross, current avoided costs)

	2012 gross TRC benefits	2012 gross TRC costs	2012 gross TRC B/C ratio	2012 gross therms
Site-specific	$ 7,620,679	$ 6,532,095	1.17	531,298
Non-res Psc clothes washers	$ 3,837	$ 13,099	0.29	927
Non-res Psc food service	$ 172,070	$ 168,253	1.02	41,008
Non-res Psc windows/insulation	$ 342,781	$ 297,672	1.15	54,182
Non-res Psc non-res HVAC	$ 1,156	$ 672	1.72	200
Res Psc ES home	$ 219,837	$ 239,360	0.92	24,231
Res Psc res HVAC	$ 2,398,646	$ 2,285,233	1.05	310,887
Res Psc water heat	$ 73,825	$ 52,796	1.40	23,546
Res Psc insulation	$ 834,477	$ 694,421	1.20	108,156
Res Psc appliance	$ 228,859	$ 74,335	3.08	26,922
	Cost of non-energy pgms	$ 880,206		
	Portfolio allocated non-incent ut. Cost	$ 313,644		
Gas portfolio overall	$ 11,896,167	$ 11,551,784	1.03	1,121,358
Site-Specific	$ 7,620,679	$ 6,532,095	1.17	531,298
Non-res prescriptive	$ 519,845	$ 479,695	1.08	96,317
Res prescriptive	$ 3,755,643	$ 3,346,144	1.12	493,742
Realization rate on site-specific	TRC benefits	TRC costs	TRC B/C ratio	
100%	$ 11,896,167	$ 11,551,784	1.03	
80%	$ 10,372,031	$ 11,551,784	0.90	
60%	$ 8,847,895	$ 11,551,784	0.77	

Table 9: 2012 Natural Gas Local Portfolio (net, current avoided costs)

	2012 net TRC benefits	2012 net TRC costs	2012 net TRC B/C ratio	2012 net therms
Site-specific	$ 5,715,509	$ 4,978,102	1.15	398,473
Non-res Psc clothes washers	$ 3,492	$ 12,301	0.28	807
Non-res Psc food service	$ 153,239	$ 154,115	0.99	35,677
Non-res Psc windows/insulation	$ 301,307	$ 270,659	1.11	47,139
Non-res Psc non-res HVAC	$ 1,006	$ 597	1.69	174
Res Psc ES home	$ 161,800	$ 180,987	0.89	17,834
Res Psc res HVAC	$ 1,463,174	$ 1,471,654	0.99	189,641
Res Psc water heat	$ 44,310	$ 34,137	1.30	13,877
Res Psc insulation	$ 646,557	$ 601,894	1.07	69,004
Res Psc appliance	$ 104,359	$ 44,026	2.37	11,268
	Cost of non-energy pgms	880,206		
	Portfolio allocated non-incent ut. Cost	313,644		
Gas portfolio overall	$ 8,594,754	$ 8,942,320	0.96	783,894
Site-Specific	$ 5,715,509	$ 4,978,102	1.15	398,473
Non-res prescriptive	$ 459,045	$ 437,671	1.05	83,796
Res prescriptive	$ 2,420,200	$ 2,332,697	1.04	301,624
Realization rate on site-specific	TRC benefits	TRC costs	TRC B/C ratio	
100%	$ 8,594,754	$ 8,942,320	0.96	
80%	$ 7,451,652	$ 8,942,320	0.83	
60%	$ 6,308,550	$ 8,942,320	0.71	

Table 10: 2013 Natural Gas Local Portfolio (gross, current avoided costs)

	2013 gross TRC benefits	2013 gross TRC costs	2013 gross TRC B/C ratio	2013 gross therms
Site-specific	5,469,751	2,872,942	1.90	379,950
Non-res Psc clothes washers	1,697	2,005	0.85	300
Non-res Psc food service	103,068	88,665	1.16	28,351
Non-res Psc windows/insulation	227,805	191,097	1.19	47,436
Non-res Psc non-res HVAC	867	648	1.34	200
Res Psc ES home	164,878	234,797	0.70	24,231
Res Psc res HVAC	1,798,984	2,235,449	0.80	310,887
Res Psc water heat	44,536	28,983	1.54	20,646
Res Psc insulation	377,892	278,609	1.36	65,305
Res Psc appliance	184,870	69,158	2.67	26,152
	Cost of non-energy pgms	880,206		
	Portfolio allocated non-incent ut. Cost	220,791		
Gas portfolio overall	$ 8,374,349	$ 7,103,350	1.18	903,456
Site-Specific	$ 5,469,751	$ 2,872,942	1.90	379,950
Non-res prescriptive	$ 333,438	$ 282,415	1.18	76,286
Res prescriptive	$ 2,571,160	$ 2,846,996	0.90	447,220
Realization rate on site-specific	TRC benefits	TRC costs	TRC B/C ratio	
100%	$ 8,374,349	$ 7,103,350	1.18	
80%	$ 7,280,399	$ 7,103,350	1.02	
60%	$ 6,186,449	$ 7,103,350	0.87	

Table 11: 2013 Natural Gas Local Portfolio (net, current avoided costs)

	2013 net TRC benefits	2013 net TRC costs	2013 net TRC B/C ratio	2013 net therms
Site-specific	4,102,313	2,211,425	1.86	330,556
Non-res Psc clothes washers	1,476	1,878	0.79	261
Non-res Psc food service	89,669	82,876	1.08	24,665
Non-res Psc windows/insulation	198,191	178,383	1.11	41,269
Non-res Psc non-res HVAC	755	597	1.26	147
Res Psc ES home	121,350	180,987	0.67	14,781
Res Psc res HVAC	1,097,380	1,471,654	0.75	183,228
Res Psc water heat	26,248	21,026	1.25	13,172
Res Psc insulation	241,095	237,577	1.01	27,332
Res Psc appliance	77,375	37,833	2.05	-
	Cost of non-energy pgms	880,206		
	Portfolio allocated non-incent ut. Cost	220,791		
Gas portfolio overall	$ 5,955,853	$ 5,525,232	1.08	635,412
Site-Specific	$ 4,102,313	$ 2,211,425	1.86	330,556
Non-res prescriptive	$ 290,091	$ 263,734	1.10	66,342
Res prescriptive	$ 1,563,449	$ 1,949,076	0.80	238,513
Realization rate on site-specific	TRC benefits	TRC costs	TRC B/C ratio	
100%	$ 5,955,853	$ 5,525,232	1.08	
80%	$ 5,135,391	$ 5,525,232	0.93	
60%	$ 4,314,928	$ 5,525,232	0.78	

Summary

Establishing and maintaining a cost-effective natural gas DSM portfolio has always been more difficult than achieving the same results from the electric portfolio. The natural gas portfolio challenges include lower avoided costs, the passive nature of many natural gas end-uses and the relative lack of the rapid development of cost-effective efficiency technologies. The historic lows expected in the natural gas avoided cost in the future make these challenges even more severe.

The recommendations made as a result of this optimization process will shift the DSM portfolio towards one which has a higher likelihood of being cost-effective in a lower avoided cost environment. This inevitably leads to lower levels of acquisition and a smaller menu of programs. Unfortunately, this is an inescapable requirement to achieve a sustainable portfolio.

The more challenging environment also places a greater emphasis on the need for diligent management of programs and the overall portfolio. It is likely that timely program revisions, including program redesigns, terminations and possibly launches, will be identified before the 2013 DSM Business Plan comprehensively reviews the overall portfolio. These observations should be acted upon as expediently as possible to retain the narrow cost-effective margin of the natural gas portfolio.

Avista has two additional opportunities to review the natural gas portfolio during 2012. In approximately June, 2012 the avoided cost stream coming out of the Avista natural gas IRP process is expected to be available in draft form. The IRP itself will not be filed until August 31st. Sometime in August, the Company will begin to develop its 2013 DSM Business Plan, which is due to be filed with the UTC on or before November 1, 2012. Given the nearness of these two dates, it is likely that these two analytical opportunities will be collapsed into a single evaluation, leading towards the DSM Business Plan. However, intermediate results in that process will be available to program managers in the event that changes to programs are necessary.