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RECOMMENDED DESIGN PROCEDURE FOR CONDUCTOR OPTIMIZATION

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ABSTRACT

Selection of the conductor size is one of the most critical design decisions for a transmission line engineer to design a transmission line that will yield the lowest cost over the design life of the transmission line. As the conductor increases in size so does the cost of the line. This is due to both the higher costs for a larger conductor and the more robust structures that are required to adequately support the larger conductor. However, a larger conductor can significantly increase value streams of the transmission year over its lifecycle. Over an entire lifecycle of a transmission line these value streams can be significant and often outweigh the additional capital expense costs. How should an engineer model and determine the optimal conductor size for a specific project? What are the critical variables that will govern the conductor selection? This paper will provide a procedure to determine which conductor size will minimize the total lifecycle costs.

Minimizing the total transmission line lifecycle costs is often referred to as conductor optimization. This involves both technical engineering and financial modeling. Reliability requirements have traditionally driven the need for new transmission lines that focused on alleviating overloads during contingency scenarios for the lowest lifecycle cost. In a modernized grid, new transmission lines will be driven more by economics which need to be factored into conductor optimization. These factors include reducing system losses and enabling markets to operate with a lower cost of energy so that the market receives a net benefit for investing in the transmission line.

This paper will provide an optimization example using five different conductor types that will provide adequate levels of thermal ratings, electromagnetic field (EMF), Corona (audible noise and radio interference). These five conductor types will each be analyzed for their own specific capital expenses and the lost revenue from electrical losses for each of the conductors. These values, along with others, will be used in creating a financial model to determine the conductor which yields the lowest total lifecycle cost.

CONDUCTOR OPTIMIZATION BACKGROUND

As with any analysis or design there are several different ways to determine an optimal conductor. The procedure recommended below is just one way to determine a conductor size that will yield a lowest life cycle cost [1]. This recommended procedure for conductor optimization can be broken out into the following six steps:

1. Transmission Line Application
2. Minimum Required Conductor Size
3. Initial Conductor Set Selection
4. Transmission Line Capital Investment Costs
5. Life Cycle Benefit of Value Streams
6. Financial Modeling

In the sections below we will dive into each of these six steps and present methods of calculating the variables that will be needed to run a financial model to determine which conductor will yield the lowest lifecycle cost.

RECOMMENDED DESIGN PROCEDURE FOR CONDUCTOR OPTIMIZATION

STEP 1 – TRANSMISSION LINE APPLICATION

The first step in this optimization process is to recognize and identify the value streams of the transmission line to be optimized. Transmission lines are built for two primary purposes: 1) transmission planning and 2) renewable energy integration. Transmission planning builds new transmission lines through finding future reliability issues in the grid or by optimizing the market operation of a control area. The value streams from a transmission planning perspective are reduced system losses and lower market prices. Renewable integration builds new transmission lines to connect new renewable generation to the grid. We specifically call this out as renewable integration rather than generation integration because traditional generators typically have short transmission lines to interconnect them a strong point in the grid. The value stream from a renewable integration perspective is a lower cost of interconnection and lower losses which result in more energy from the project.

Transmission planning is the investigation of future grid scenarios and their impact on grid reliability. The energy transition has caused the displacement of centralized generation with de-centralized renewables which have caused new stress points in the grid. Traditionally the grid was constructed to transfer power from centralized generation stations to load centers (now considered smart homes in Figure 1). The grid was built such that if failures were to occur there was ample capacity in the grid to ensure loads were always served. The energy transition has shifted generation away from these centralized generation stations and distributed it throughout the power system. In some cases, this does achieve better reliability, but in most cases the resource pockets that support renewables energy are typically far from load centers and not adequately sited to take advantage of reinforced backbone transmission infrastructure.

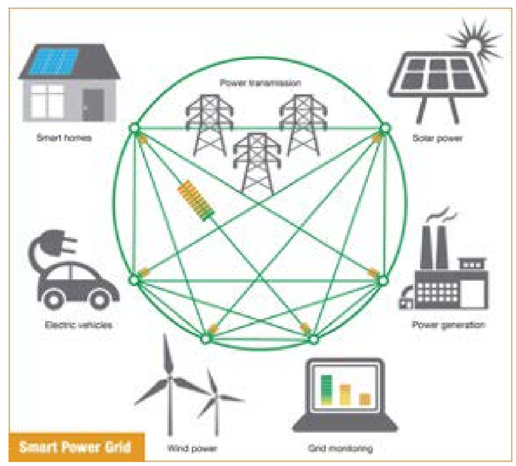

Figure 1 – Diagram of power grid infrastructure [2]

Value streams that are important to consider in the optimization of the conductor for transmission planning applications include reduced system losses and lower market prices. Typically, new transmission lines determined as an output of transmission planning are placed on paths of congestion. A new transmission line that relieves parallel paths that were previously congested also lowers the impedance of that general transfer from generation to load. The lower impedance of the transfer from generation to load can reduce system losses. In a similar fashion, the reduction of congestion unlocks additional low-cost generation in a system that may have been previously curtailed due to congestion. The additional low-cost generation lowers market prices in areas with markets and lowers the cost of generation in areas with no markets.

Renewable integration is the construction a of a transmission line to connect a new renewable energy project to the grid. These transmission lines have historically been 0-15 miles long. As resource pockets continue to be built out, developers will have to build transmission lines longer and longer to get to adequate points of interconnection. This creates transmission lines that may need to be over 50 miles long. This creates an additional strain on the project and requires the transmission line be optimized to ensure it is not causing undue cost to the project and loss of energy from the project.

Value streams that are important to consider in the optimization of the conductor for renewable integration applications include reduced cost of interconnection and reduced losses. The reduced cost of interconnection typically appears in the form of access to new transmission infrastructure that is not congested with other existing renewable projects. This could also manifest in the form of access to a market that a resource pocket traditionally did not access due to proximity. The second value stream is the reduced loss from the transmission line. All the power from the renewable project must be transferred through the transmission line to get to the grid. Each MW of loss in the transmission line is a MW that was not delivered to the grid and an additional MW for which the project was not compensated.

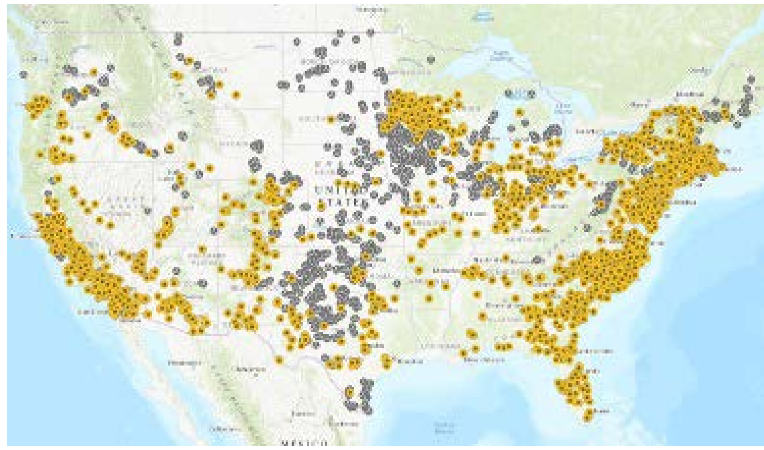

Figure 2 – Wind (gray) and solar (yellow) buildout in the United States [3].

STEP 2 – MINIMUM REQUIRED CONDUCTOR SIZE

One of the first steps to conductor optimization is to determine the minimum conductor size that will meet the thermal [4], audible noise (AN), and electric and magnetic field (EMF) limits.

To determine the minimum required conductor size, the thermal rating must first be found. The thermal rating is usually specified by a maximum allowable temperature for the conductor. The temperature equates to a sag in the conductor, minimum height from the ground, pole height, and physical stress limits. A common conductor thermal limit is 100 °C. Once you have determined the thermal limit, software can be applied to calculate what current load and conditions are needed to meet the temperature. From there the amount of power that can be delivered by the transmission line is determined. It may be necessary to conduct an iterative process on the thermal rating to meet individual power requirements.

As conductor voltages increase the air becomes ionized. This air ionization produces sound in the human audible range. Inclement weather (rain, snow, fog, etc.) can add to the level of sound, or audible noise, on the transmission line due to sudden vaporization of the water molecules. Typical limits used for audible noise are based on Environmental Protection Agency (EPA) publications, IEEE guidelines or World Health Organization (WHO) publications.. In this paper the 55 dBA at the edge of the ROW as defined by the EPA will be used. AN limits vary from state to state and even vary by counties within states. It is recommended that local regulations be consulted and determined as soon as possible in the design process. AN is almost solely a function of the conductor diameter and voltage. As the conductor diameter increases, the voltage gradient on the conductor surface decreases which decreases the amount of ionization and reduces the audible noise.

Electric fields are a function of geometry of the structures (spacing of phases, location of phases relative to each other i.e. ABC, CBA etc), voltage of the transmission line, and the distance to the point of measurement. Certain structure types or phasings allow for field cancellation of the electric fields and hence a reduction in the measured values at the location of interest. Other geometries or phasing's result in an increase in the electric field measurement. The International Commission on Non-Ionizing Radiation Protection (ICNIRP) publishes guidelines for typical exposure levels. The guidelines provide occupational exposure limits for workers in the right-of-way or near the structures.

Magnetic fields, like electric fields, are a function of the geometry of the structures, current carried by the conductors, and distance to the point of measurement or interest. ICNIRP also publishes occupational exposure guidelines for magnetic fields.

STEP 3 – INITIAL CONDUCTOR SET SELECTION

There are many other factors that play into conductor selection besides minimum required ampacity. After determining the smallest conductor that meets the requirements of thermal ampacity, audible noise and EMF limits, there are still two major items to be considered:

- Electrical losses
- Differential capital expense of the transmission line associated with each different conductor

To run this analysis, an array of different conductor sizes and types should be considered for the project. It is recommended to consider a broad selection of conductor types in the analysis. It is recommended to select four or five different conductor sizes to analyze [5]. Begin with the smallest conductor that satisfies the requirements of thermal rating, audible noise, and EMF. Then increase the conductor size by ampacity increments of 10-15% per conductor. It is recommended to model at least five different conductors. This may seem daunting at first, but it will likely be easy to rule out some choices immediately due to high cost, limited availability, etc.

Lastly, once you have your initial list of conductor choices to analyze, it is important to work with your supplier to get pricing for your choices. You may not be able to get exact pricing, however, in our experience, your supplier may be able to quote you percent cost increase for each type over the smallest. This is equally useful, and the method to apply these costs and/or percentages will be discussed in step 6.

STEP 4 – TRANSMISSION LINE CAPITAL INVESTMENT COSTS

Once a base list of conductors has been chosen, the next logical step is to analyze structure heights and weights. There are several points to consider when selecting structure types for this analysis. Right-of-way (ROW) is a significant cost to any project. Many times, the right-of-way is already determined, and often already purchased by the time an engineer is brought in and conductor selection is required. Other times, the engineer is brought in early enough to help with the ROW width requirements, making it necessary to include the ROW acquisition costs in the analysis. For example, the ROW required for very long span H-frames will be vastly different than braced-post monopoles with shorter spans, and this will add another layer to your capital cost analysis. Whether a part of the ROW selection process or if you already know the ROW, you will also need to select structure families to analyze. There are many factors that go into structure family selection: 1) ROW width (if it has not already been selected), 2) Geographic location (ex. – if you are within reasonable proximity to a concrete pole manufacturer, concrete may be a valid choice. If you are in the mountains, construction access may limit your available choices), 3) Contractor feedback, 4) Client/Owner preferences, 5) Cost of raw materials and fabrication, 6) Design complexity, 7) Structure Geometry, and 8) Future Operation and Maintenance Costs.

It will be best to analyze multiple structure types. For example, Steel monopoles vs. Wood H-frames vs. Steel H-frames. Or, if you have it narrowed down to steel monopoles, it may be a useful exercise to look at braced post vs. davit arm suspension structures or guyed vs. concrete foundation angle structures. There are many different configurations that may be a good fit for a project, and the best cost comparison will include multiple types and may require multiple iterations. This may sound like a lot of work – and it can be! However, it is engineering hours well-spent in the long run.

Also, it will likely be easy to rule out several possibilities immediately. Perhaps you already know from experience that lattice towers will not be feasible, or that wood structures are not preferred by the client, etc.

Once the structure families are selected for analysis, the next step is to determine heights/classes and/or heights and weights of structures for each conductor type. The recommendation is to use the “typical” structure for each type. For example, no need to model an entire line and check every single tangent, angle, and dead-end height - use a typical sample of each to simplify. This can be done using PLS-POLE in combination with PLS-Lite. PLS-POLE has a useful tool built-in called “Steel Pole Optimizer,” which can aid in getting steel pole weights once tensions are established. And of course, if using pre-engineered or wood height/class structures, you can easily determine that with PLS-POLE as well. PLS-POLE’s optimizer will get you close for the purposes of analyzing steel, however, if more accuracy is desired, it may be beneficial to work directly with your steel pole manufacturer to get some preliminary designs and weights for use in the financial analysis and foundation estimates, which is the next.

If your transmission line will be using any foundation structures, the next logical step is to estimate foundations. It’s best to have a geotechnical report for the project area, however, if one is not available in the time window needed for the conductor selection analysis, publicly available data is often available for most parts of the country which detail some minimum soil inputs for analysis with foundation design software. Taking soil profile data and the structure ground line moments from the previous step, foundations can be estimated using tools such as MFAD, LPile, or CAISSON.

Lastly, installation costs and operations/maintenance costs must be considered. H-frames will cost a different amount to install than steel monopoles on foundations and larger and/or unique conductor types may be more costly to install and must be considered in the financial analysis. The required maintenance for Wood H-Frame structures may be higher than the required maintenance for steel monopoles. All of the differential costs for a structure family and conductor size need be calculated and included in the cost comparisons. Feedback from the selected contractor is very valuable here. Alternatives would be in-house estimating tools, historical project information, or working with a construction estimator.

Estimating the capital investment costs is by far the most time consuming and difficult. It requires creativity, engineering calculations, and teamwork with others who may provide input such as suppliers and contractors. However, keep in mind, this is where the value engineering lies. The more work done at this point, the more long-term value and savings will be achieved. This is the fun part of engineering. This is not picking a design that “has worked for years” off of a shelf – it’s real problem solving. And the longer the transmission line, the more it pays to spend time on this exercise.

STEP 5 – LIFE CYCLE BENEFIT OF VALUE STREAMS

There are several value streams of the transmission line’s design that can be optimized depending on the transmission line’s application. Total system losses, market prices, line losses, and interconnection cost can be optimized against the higher cost of larger conductors. In all cases, it is important to capture the life cycle values for these metrics rather than snapshot metrics. In the consideration of line losses, it is important to consider the annual energy weighted losses rather than just the line losses at rated power.

RECOMMENDED DESIGN PROCEDURE FOR CONDUCTOR OPTIMIZATION

The value streams of a transmission line are typically captured on an annual timescale at an hourly timescale, also known as an 8760 (number of hours in a year). The value stream for every hour of a typical year is calculated and then combined to determine the value from a typical year. Depending on the value stream various, the typical year value can be used in financial models to determine the value of the transmission line throughout its lifespan.

From the transmission planning perspective, the reduction in market price is becoming an increasingly important metric for the transmission line. This is done by using a software that can calculate locational marginal prices (LMPs) for future planning scenarios. These future planning scenarios represent how the grid's market will settle in the future with a variety of assumptions made on cost of generation, type of generation, and cost of generation. The outcome of these simulations is typically congestion that transmission planners must create mitigation. Transmission planners test mitigation by incorporating them into the future scenario and determining how much the market could save in cost of generation. The difference in cost of generation with conductor A used as mitigation for a specific path with the cost of generation with conductor B, can be used in the conductor optimization as the value added to the market by selecting a specific conductor.

From the renewable integration perspective, the reduction in line losses is typically the most important value stream. Renewable energy is intermittent, which means that its production goes up and down based on its resource. To properly calculate the losses from a transmission line for a renewable project, the 8760 energy yield of the plant should be utilized to determine the annualized losses from the renewable energy plant. The annualized losses will always be lower than the peak injection loss percentage because the renewable energy plant does not operate at 100% for the entire year. Typical, capacity factors of wind projects are generally around 40-45% and typically capacity factors for solar are 25%-30%.

STEP 6 – FINANCIAL MODEL

The financial model can be broken down as shown in Figure 3. The transmission line length, the transmission line design life and the generation name plate capacity for gen-tie lines are usually all known at the beginning of the transmission line design and therefore descriptions of those variables are not included here. However, other financial variables will need additional discussion:

DIFFERENTIAL COST INVESTMENT

(Required Input Variables)
- CAPITAL INVESTMENT OF DIFFERENT TRANSMISSION LINES
  - Transmission Line Length
  - Structure Types
  - Conductor Size

+

FUTURE VALUE OF ACCRUED INTEREST FROM TODAY'S ADDITIONAL CAPITAL INVESTMENT

(Required Input Variables)
- DIFFERENTIAL CAPITAL INVESTMENT
- COST OF CAPITAL
- DESIGN LIFE

+

LOST REVENUE OF VALUE STREAMS OVER FULL DESIGN LIFE

(Required Input Variables for Electrical Loss Value Stream)
- PRICE OF POWER
- ANNUAL INCREASE IN PRICE OF POWER
- DESIGN LIFE
- ELECTRICAL LOSSES
- NAME PLATE GENERATION
- GENERATION CAPACITY FACTOR

=

TOTAL DIFFERENTIAL COST OF TRANSMISSION LINE OVER FULL DESIGN LIFE

Figure 3: Financial Model for Conductor Optimization

DIFFERENTIAL CAPITAL INVESTMENT

Determining the Capital Investment of the transmission lines is discussed in detail under Step 4 above. The differential capital Investment (CI) may be as simple as the difference in cost for materials and construction. The critical point is to capture all the cost differences between the different structures systems and different supported conductors. After performing the capital Investment calculations for the different structural systems and the different supported conductors, the line with the lowest capital investment is the baseline. This transmission line with the lowest capital investment will be referred to as “Line A”. Every other transmission line with a higher capital investment will be compared to “Line A”. The differential capital investment is simply:

$$[CE_{LINE\_B}] - [CE_{LINE\_A}] = \Delta\_CE_{B\&A} \qquad \textit{Equation 1}$$

$\Delta\_CE_{B\&A}$ *= Differential Capital Expense Between Lines B and A*

Additional differential capital investment values should also be calculated for transmission line supporting other conductor sizes such as the differential capital investment between line C, D or E, and line A.

FUTURE VALUE OF ACCRUED INTEREST FROM TODAY’S ADDITIONAL CAPITAL INVESTMENT

By designing a transmission line with a larger conductor, more capital investment is required at the beginning of the project. This additional capital investment could have been invested in a different project, or a different industry, and depending on the clients cost of capital it could yield significant returns on the initial investment. By building a line with a larger conductor the client would not have that same available capital to put towards an alternative project or investment. The estimated returns on alternative investments must be calculated and included in the cost comparisons between the conductors. A compound interest formula can be used to estimate the returns on alternative investments. There are three main variables that determine Accrued Interest Calculations: differential capital investment, design life, and Cost of Capital.

COST OF CAPITAL

Cost of capital is the future value of today’s additional capital investment assuming an annualized rate of return compounding over the design life of the project. The cost of capital is a weighted average of the return on investment (ROI) of multiple different projects. Another way to think of this is, where is the best place to put our financial resources? Should the client invest in oversizing the conductor or put their money in some alternative investment.

Cost of capital will be different for every client due to the client’s specific risk tolerance and economic conditions. Most clients, whether they are utilities or renewable developers know what value should be used for their cost of capital. Typically, utilities assume lower cost of capital values generally in the range of 2-5% and renewable developers estimate higher cost of capital values generally in the range of 5-8%.

LOST REVENUE OF VALUE STREAMS OVER FULL DESIGN LIFE

As discussed in Step 5 above, there are several different value streams for transmission lines all of which have their own associated monetary values. The variables listed below are specifically for estimating the value of lost revenue due to electrical losses in the transmission line. Calculating this total lost revenue over the full design life of the transmission line is critical to include in the financial model. The key variables for calculating the electrical losses and the lost revenue from electrical losses are, price of power, annual increase in price of power, electrical losses, name plate generation capacity and generation capacity factor. These variables will be discussed in detail below.

PRICE OF POWER

Ten or so years ago the financial contracts that determined the price of power were relatively simple. Often there was a "Fixed" price for the power that could be used to determine the financial metrics. Over the past 10 years however, more and more profit driven entities have entered power markets and value of power in the grid has become significantly more complicated. Financial contracts such as virtual PPAs, proxy revenue swaps, and other financial hedges, are all ways that energy offtakers can maximize their profits while pushing the financial risk down onto the owners of the physical grid assets.

One of the more difficult financial metrics to model is cost of energy in the grid. As an example, the eastern interconnection has several Independent System Operators (ISO) that operate their own markets and several vertically integrated utilities that manage their own fleet of generation. Therefore, the cost of energy can vary dramatically in terms of how it is determined or even magnitude across the eastern interconnection even though it is a single AC network. In an ISO market, the cost of energy can change in real time and varies due to supply and demand of the power. At any given hour of the day the cost of energy can vary significantly. LMP software that accounts for all these factors can be carefully used to determine the value of energy in the grid for future years [6].

It is highly recommended to work with the client to determine what the value of energy is for their specific asset and how it is operated. The value of energy for the asset is important to determine how the impact of larger conductor sizes can benefit the asset over its lifetime.

ANNUAL INCREASE IN PRICE OF POWER

This financial metric is becoming less and less common especially in renewable generation, however there are still some markets where annual increases to energy are included in the financial contracts. If this metric is not included in the energy contracts, then the relative value of the energy will reduce year over year. This is due to how inflation causes the value of a dollar in the future to be worth less than it is worth today. If this metric is included in the financial contracts, then it is important to perform your financial modeling using this annual increase in the price of energy to accurately predict the future value of the power.

ELECTRICAL LOSSES

Using software like PSSE loss percentages can be calculated for different conductor sizes. For most forms of generation today, they are not producing at their full name plate capacity all the time. The production will vary with time. To analyze losses accurately an annualized loss power production must be defined [7].

GENERATION CAPACITY FACTOR

For most forms of generation, the amount of power produced varies with time. In other words, only occasionally does the generators produce at the full name plate capacity. The rest of the time the generators are producing a lower power output, sometimes much lower power output. Capacity Factor can be calculated using the following equation:

$$\textit{Capacity Factor} = \frac{\textit{Annual Energy Production (MWh)}}{\textit{Nameplate Output (MW)}*8760\ \frac{hr}{year}} \qquad \textit{Equation 2}$$

The above equation is very generic. The tricky part is in predicting the actual energy produced in a particular year. Therefore, a typical year energy production is used. The typical year represents the average over a large timescale, for example 30 years. The actual annual energy production for a particular year may be higher or lower than the typical year, but over the lifetime of the plant the highs and lows should average towards the typical year. The typical year energy production is generally referred to as an 8760. By applying the 8760 data to a wind or solar farm accurate predictions can be made to estimate the total annual energy production.

Traditional generators have historically had very stable capacity factors because load behavior is predictable with a relatively high certainty, compared to wind and solar resource. However, the intermittency of renewables, has introduced additional uncertainty throughout the grid. Now the capacity factor of traditional generation is also dependent on the intermittency of renewables due to load and generation balance. For example, controllable resources are typically used to make up the uncertainty of intermittent renewables which make the capacity factor of traditional generators more uncertain.

EXAMPLE: RENEWABLE APPLICATION – CONDUCTOR OPTIMIZATION

An example of this optimization procedure will be completed under the context of a transmission line for a large renewable energy wind farm that measures 50 miles in length. The design life of the wind farm is 30 years. The design voltage of the line is 345 kV. The name plate capacity of the project is 1200 MW

STEP 1 – TRANSMISSION LINE APPLICATION

This application focuses on a renewable energy integration application. For simplicity, we will focus on optimizing the conductor around line losses. Interconnection costs are also important in the context of a renewable integration application but are very site specific and would be an arbitrary complexity for this example.

STEP 2 – MINIMUM REQUIRED CONDUCTOR SIZE

The AN and EMF predictions were taken from the Corona and Field Effects Program (CAFEP) created by the Bonneville Power Administration (BPA). The software is based upon empirical measurements taken by BPA and is an accepted industry tool. The software allows for setting different increments to predict values as well as providing a “rain” and clear AN value. For the AN prediction a “rain” condition was reported.

The EMF predictions are primarily dependent on the voltage level, load current and the distance to the edge of the ROW. These are typically more expensive to adjust as they require structure, loading, and ROW sizing changes.

The example transmission line has the following properties:

- Each phase consists of bundled (2) sub-conductors 18 inches apart
- Elevation of 7600 ft above sea level
- Line must support 1200 MW nameplate capacity
- Right-of-Way (ROW) of 150 ft width
- Voltage of 362 kV (1.05 pu on a nominal 345 kV line)
- Transmission line conductor family specified to be ACSR
- Structure type specified to be Steel Monopole

The conductor thermal rating will tell us what load current can be carried and whether we meet the goal of 1200 MW of nameplate capacity.

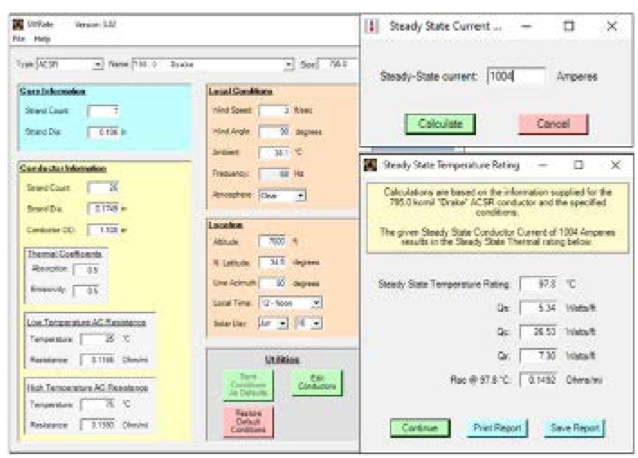

Figure 4 on page 10 shows: SWRate - IEEE 738 Calculator

The thermal limit set for our ACSR conductor is 100 °C. Using IEEE 738 [4] as a guideline the conductor temperature and current limit could be determined using the SWRate software. Figure 4 on page 10 shows the input screen for this software.

As can be seen from the figure, there are other inputs besides the conductor type that can be of significance. Some of the inputs to be considered are:

- Elevation
- Location (Longitude, latitude, time of day, time of year)
- Local conditions (Wind Angle to the line, power frequency, wind speed)

From the thermal analysis the ACSR 795 Drake, in a 2-bundle configuration, would be able to carry 2008 Amperes of current per phase and remain below the maximum operating temperature of 100°C.

Table 1 below lists the conductor design limits and the predicted values for each parameter based on the transmission line case selected. From the calculated AN value of 54 dBA it can be concluded that the ACSR 795 Drake is the minimum conductor to be used to remain under the 55 dBA design limit recommended by the EPA. The electric and magnetic field limits were taken from the guidelines published by the International Commission on Non-Ionizing Radiation Protection (ICNIRP). As can be seen from the table, the predicted values for occupational exposure are well below the maximum recommended values.

CONDUCTOR	SUB-CONDUCTOR OVERALL DIAMETER (in.)	CONDUCTOR MAX OPERATING TEMP (deg C)	MAXIMUM AN AT ROW (dBA)	ELECTRIC FIELD AT ROW (kV/m)	MAXIMUM ELECTRIC FIELD (kV/m)	MAGNETIC FIELD AT ROW (mGauss)	MAXIMUM MAGNETIC FIELD (mGauss)
Design Limit	--	100	55.0	12.0	12.0	12E6	12E6
(2) 795kcmil ACSR "Drake"	1.107	97.8	54.0	0.84	1.40	37.1	73.2

Table 1: Minimum Conductor Size Results

STEP 3 – INITIAL CONDUCTOR SET SELECTION

For this study, the minimum conductor size has been shown to be 2-bundle 795 "Drake" ACSR, as previously shown, based on minimum electrical criteria. An array of different ACSR conductor types ("Drake" and larger) will be considered to keep the example from being exceedingly complicated for presentation purposes. The analysis started with 2-bundle "Drake" ACSR as the least-cost conductor, and an additional four were selected (see Table 2). Each "up-sized" ACSR represents an increase of 10-15% in ampacity. The largest conductor represented in this analysis was 2-bundle 1590 "Falcon" ACSR.

SUB-CONDUCTOR PROPERTIES ALUMINUM CONDUCTOR STEEL REINFORCED (ACSR)									
CODE WORD	SIZE (AWG or kcmil)	STRANDING (Al/Stl)	COMPLETE CABLE DIAMETER (in)	WEIGHT PER 1000ft TOTAL (lbs)	RATED STRENGTH (lbs.)	DC @ 20° C	AC @ 75° C	AMPACITY @ 75° C	INCREASE IN AMPACITY RELATIVE TO SMALLEST CONDUCTOR [%]
Drake	795	26/7	1.107	1093	31,500	0.0214	0.0263	907	100%
Curlew	1033.5	54/7	1.245	1330	36,600	0.0165	0.0211	1047	115%
Grackle	1192.5	54/19	1.337	1531	41,900	0.0144	0.0184	1140	126%
Martin	1351.5	54/19	1.424	1735	46,300	0.0163	0.0163	1232	136%
Falcon	1590	54/19	1.544	2041	54,500	0.0108	0.0140	1359	150%

Table 2: Initial Conductor Selection Properties [8]

This particular group of ACSR conductors was strategically chosen to help speed up the estimation of the transmission line capital investment costs. This group of conductors has very similar aluminum to steel ratios. This simplifies the structure analysis because the sag profiles will be virtually the same for all five conductors. Therefore, once we determine structure span lengths and the associated structure heights for the first conductor, (2) 795kcmil ACSR "DRAKE", the structure heights and span lengths can remain constant as you increase conductor size - only the individual structure weights will change.

STEP 4 – TRANSMISSION LINE CAPITAL INVESTMENT COSTS

For this example, the transmission line ROW width was already established at 150ft. With a set ROW width, some structure types or span lengths can be ruled out. Certain materials can also be ruled out due to capacity or availability. For this particular example it was decided to perform capital expense estimations of just steel monopoles that could support the five conductor types listed in Table 2. A structure family consisting of a typical tangent (direct embedded, braced post), running angle, and dead-end structures was created. Some projects may benefit from davit-arm suspension tangent structures, however, for this example, braced post typical tangents were chosen. The running angle and dead-end structures are self-supporting, on a concrete drilled pier foundation.

The procedure used was to create a general steel monopole with identical conductor attachment points. The design loads that controlled the deadends and running angle structures were the NESC Rule 250B – Heavy Region loading. The design loads that controlled the tangents were NESC Rule 250C – 90mph. Once conductor tensions were determined in PLS-Lite, PLS-POLE was once again used to determine steel pole weights. The PLS-POLE Steel Pole Optimizer tool was used to do this. This method worked well for a fictitious project, however remember, if this were an actual project for a client, it would have been a more accurate analysis to work directly with a steel pole vendor, providing .LCA files from PLS-POLE for a vendor to come up with the most efficient design for the structure families for each conductor type.

To estimate foundation costs, the foundation diameters were estimated by increasing the anchor bolt circle diameter by a calculated amount to allow for adequate clearance between longitudinal rebar, anchor bolts and earth, and rounding up to the nearest whole foot increment. A desktop geotechnical report was obtained to determine approximate geotechnical parameters for different locations along these 50 miles of transmission line. The base reactions of the steel poles were taken from our PLS-Pole analysis. The preliminary foundation designs were calculated using MFAD.

Lastly, the conductor costs, structure costs, and foundation sizes were used to estimate total costs per mile of line construction. This will vary from project to project greatly, and depends on route, accessibility contractor, material availability, foundation sizes, geographic location, etc. In the case of this example, we reached out to a construction partner for assistance for a better estimate than we could provide in-house. We gave them the scenarios for all 5 conductor types, including steel weights and foundation size estimates. We also gave them the hypothetical count of dead-end structure types, running angles, and tangents. From there our construction partner was able to give us an estimate of installed costs per mile, shown in Table 3.

345 kV STEEL MONOPOLE – SINGLE CIRCUIT – TRANSMISSION LINE – ESTIMATED COST				
SUB-CONDUCTOR TYPE		TOTAL PERCENTAGE INCREASE	TOTAL BASE PRICE/ MILE	DIFFERENTIAL COST RELATIVE TO 795KCMIL "DRAKE" [$/MILE]
795	kcmil ACSR "DRAKE"	100.0%	$735,237	$0
1033.5	kcmil ACSR "CURLEW"	106.5%	$783,314	$48,077
1192.5	kcmil ACSR "GRACKLE"	110.9%	$815,481	$80,244
1351.5	kcmil ACSR "MARTIN"	117.7%	$865,477	$130,240
1590	kcmil ACSR "FALCON"	128.6%	$945,662	$210,425

Table 3: Estimated Cost of Transmission Lines Supporting Initial Set of Conductors

STEP 5 – LIFE CYCLE BENEFIT OF VALUE STREAMS – ELECTRICAL LOSS CALCULATIONS

There are several benefits that relate to increasing conductor size including improving total system losses, market prices, line losses, and interconnection cost can be optimized against the higher cost of larger conductors. For this example, the value stream that will be highlighted is in reducing electrical losses in the transmission line.

It is important to determine the operating temperature of each individual conductor to be used in the loss calculations. The resistivity values vary based upon the conductor operating temperature. The higher the operating temperature the higher the resistivity and the higher the losses. Therefore, determining the conductor operating temp under the 8760 loss current is important to accurately determine the electrical losses of the conductor.

The most common way to determine operating temperature is to follow 738-2012 – IEEE Standard for Calculating the Current-Temperature Relationship of Bare Overhead Conductors [4]. These calculations can be done by hand but there are also IEEE-738 "calculators" available. PLS-CADD has reports that can provide IEEE-738 calculations. Southwire, the conductor manufacturer, created an IEEE 738 calculator called SWRate. This method of calculating conductor temperature requires several project input variables which include the variables shown in Table 4 has certain cells color coded. The different colors represent how much impact that variable has to the operating temperature of the conductor.

Several the variables will be defined by the specific conductor selected, such as the Physical Conductor Properties and the Low and High Temp AC Resistance values. Other variables will be defined by the location of the project such as the Altitude and the Latitude. But there are several variables that change hour by hour and careful consideration and analysis should be performed to determine the appropriate input values. It should be performed again when determining the conductor operating temperature under the defined loss power output. This operating temp will be referred to as [Loss Operating Temperature]. This same process of determining the input variables should be performed when determining the [Max Operating Temperature] when the line is supporting the full "Name Plate" generation. To be clear, many of these input variables will be different for the Max Operating Temp and for the Loss Operating Temp.

The first step to calculating the electrical losses of the different conductor sizes is to determine the specific operating temperatures under the calculated loss current. This will also require defining certain variables for that will be kept constant between the different conductor sizes. Please see Table 4 below which defines the thermal coefficients, local conditions, and location of the example project.

IEEE - 738 INPUT VARIABLES AND RELATIVE IMPACT OF THE VARIABLES

Physical Conductor Properties		
Core and Conductor Strand Count =		[#]
Core and Conductor Strand Diameter =		[in]
Total Conductor Outer Diameter =		[in]
Thermal Coefficients		
Absorptivity =	0.5	
Emissivity =	0.5	
Low Temperature AC Resistance		
Temp =		[°C]
Resistance =		[Ohm/mi]
High Temperature AC Resistance		
Temp =		[°C]
Resistance =		[Ohm/mi]

Local Conditions		
Wind Speed =	3	[ft/sec]
Wind Angle =	90	[deg]
Ambient Temperature =	16.6	[°C]
Frequency =	60	[Hz]
Atmosphere Condition =	Clear	[Clear/Industrial]
Location		
Altitude =	7600	[ft]
N. Latitude =	34.5	[deg]
Line Azimuth =	90	[deg]
Local Time =	12	[hr]
Solar Day =	March, 20th	[Month & Day]

High Impact Variable =	(orange)
Medium-High Impact Variable =	(yellow)
Low Impact Variable =	(blue)

Table 4:Variables to Determine Conductor Operating Temperature for Loss Current

When calculating the thermal rating of the conductor it is important to model some sort of high temperature, i.e. 40deg C, for the ambient temperature. However, for the loss calculations the ambient temperature should not be a record high temperature. The ambient temperature should be some sort of weighted average temperature over the full year of power production. This weighted average approach should also be applied to the solar day.

The physical conductor properties and the Low and High temperature AC Resistance values will be dependent on the conductor size analyzed. Once the conductor's operational temp has been determined the electrical loss calculations can be performed for each conductor.

The losses for each design iteration were determined through an 8760 analysis of the load flow of a generic plant.

First, we extracted the line impedances from the design in PLS-CADD. The impedances from PLC-CADD consider the geometry, conductor type, and temperature to ensure we have accurate impedances for the transmission line design. The impedances are then entered into PSSE, a power flow software, to determine the losses for each hour of production from the renewable energy plant. These losses are then energy weighted to get an annualized loss percentage which can be applied against the plant's annual energy yield to determine how much energy was loss due to transmission line losses. Table 5 displays the operating temperature, electrical loss percentage and capital expense for our example project.

Financial Metric Description		345 kV SINGLE CIRCUIT TRANSMISSION LINE 50 MILES LONG ACSR CONDUCTOR Electrical Loss Results									
		(2) 785kcmil ACSR		(2) 1033.5kcmil		(2) 1192.5kcmil ACSR		(2) 1351.5ckmil ACSR		(2) 1590kcmil	
		"DRAKE"		"CURLEW"		"GRACHIE"		"MARTIN"		"FALLON"	
Input Power Production at Beginning of Line [MW]	Modeled Ambient Temperature F° [C°]	Calculated Conductor Operating Temp from SWRate [°C]	%Loss	Calculated Conductor Operating Temp from SWRate [°C]	%Loss	Calculated Conductor Operating Temp from SWRate [°C]	%Loss	Calculated Conductor Operating Temp from SWRate [°C]	%Loss	Calculated Conductor Operating Temp from SWRate [°C]	%Loss
Name Plate Capacity: 1200MW	100.6 [38.1}	97.8	3.01%	84.6	2.35%	78.5	2.06%	74.1	1.82%	69.5	1.56%
8760 Power Production Loss Analysis	612.9 [16.6]	52.0	2.24%	45.3	1.74%	42.5	1.52%	40.5	1.35%	38.4	1.16%
Capital Expense [$/50 Miles] =		$36,761,850		$39,165,700		$40,774,050		$43,273,850		$47,283,100	

Table 5: Operating Temps, Electrical Loss % and Capital Expense

STEP 6 – FINANCIAL MODEL

There are other financial variables that must be defined. The length of the line, the design life, the name plate capacity of the wind farm were known values at the beginning of the analysis and the project capacity factor can be calculated by analyzing 8760 reports for the wind intensity. The values for the price of power, the annual increase in cost of energy, also known as a price escalator, and the cost of capital are generally provided by the client or utility.

MINIMIZING TOTAL LINE COST - DESIGN VALUES		
LENGTH OF LINE =	50	miles
TRANSMISSION LINE DESIGN LIFE =	30	years
PRICE OF POWER =	$25.00	S/MWH
ANNUAL INCREASE IN COST OF POWER =	2.50%	%
COST OF CAPITAL =	6.50%	%
NAME PLATE CAPACITY =	1200	MW
PROJECT CAPACITY FACTOR =	47.72%	%
AVERAGE PRODUCTION GENERATION (CAPACITY FACTOR x NAME PLATE CAPACITY) =	572.64	MW

Table 6: Financial Variables Defined

345 kV SINGLE CIRCUIT TRANSMISSION LINE_50 MILES LONG ACSR CONDUCTOR FINANCIAL RESULTS					
FINANCIAL METRIC DESCRIPTION	(2) 795kcmil ACSR "DRAKE"	(2) 1033.5kcmil ACSR "CURLEW"	(2) 1192.5kcmil ACSR "GRACKLE"	(2) 1351.5kcmil ACSR "MARTIN"	(2) 1590kcmil ACSR "FALCON"
CAPITAL EXPENSE [$/50 MILES] =	$36,761,850	$39,165,700	$40,774,050	$43,273,850	$47,283,100
DIFFERENTIAL CAPITAL EXPENSE RELATIVE TO "DRAKE" [$/50 MILES] =	$0	$2,403,850	$4,012,200	$6,512,000	$10,521,250
FUTURE VALUE OF ACCRUED INTEREST FROM TODAY'S ADDITIONAL CAPITAL EXPENSE [$] =	$0	$13,496,094	$22,525,960	$36,560,752	$59,070,150
COST OF LOST REVENUE DUE TO ELECTRICAL LOSSES OVER FULL DESIGN LIFE [$] =	$129,117,490	$100,613,803	$87,807,047	$77,752,012	$66,658,592
DIFFERENTIAL TOTAL LIFECYCLE COST OF T-LINE [$] =	**$129,117,490**	**$116,513,747**	**$114,345,207**	**$120,824,764**	**$136,249,992**

Table 7: Differential Costs of Transmission Lines Supporting Different Conductors.

With the information provided in Table 6 and in Table 7, a financial model can be created to compare the differential total lifecycle costs for the selected conductors. As has been discussed earlier in the paper there are at least three different cost curves that need to be calculated to determine the Differential Total Lifecycle Cost of the selected conductors [5], they consist of:

TOTAL DIFFERENTIAL COST OF TRANSMISSION LIVE OVER FULL DESIGN LIFE
=
LOST REVENUE DUE TO ELECTRICAL LOSSES OVER FULL DESIGN LIFE
+
FUTURE VALUE OF ACCRUED INTEREST FROM TODAY'S ADDITIONAL CAPITAL INVESTMENT
+
DIFFERENTIAL CAPITAL INVESTMENT

Figure 5 displays these cost curves for the initial set of selected conductors.

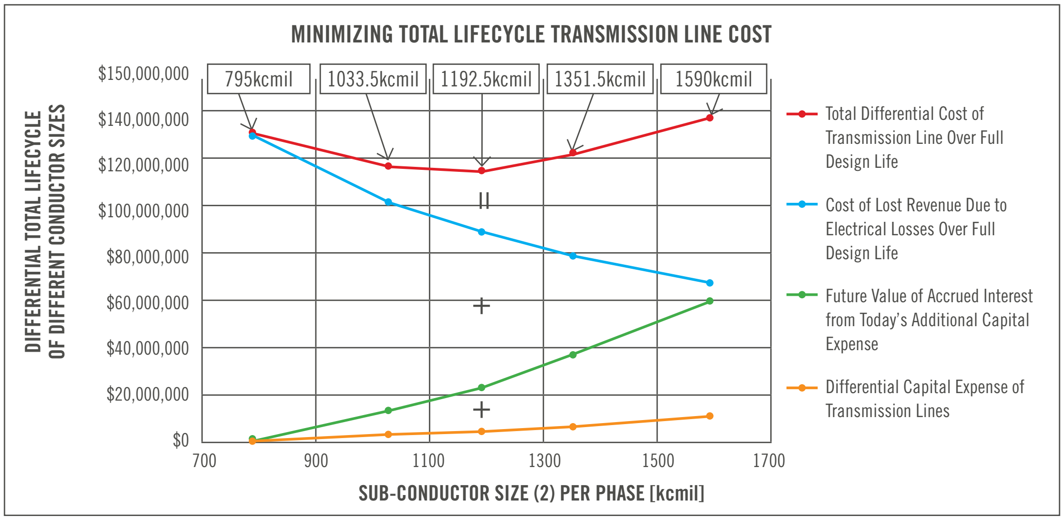

Figure 5:Differential Total Lifecycle Cost.

As can be seen in Figure 5 & Table 7, that the 1192.5kcmil ACSR "GRACKLE" yields the lowest differential total lifecycle cost of the five conductors analyzed. Therefore, the bundled (2) 1192.5kcmil ACSR "GRACKLE" would be the optimal conductor from the five conductors analyzed.

CONCLUSIONS

Regardless of the transmission line's design application, selecting the appropriate conductor size can create very large savings over the design life of the transmission line. Typically, as the length of the line increases the added value of performing a conductor optimization analysis goes up. Also, as the electrical loading on the conductor increases the value of performing a conductor optimization analysis increases. The smallest conductor that meets the electrical requirements does not generally yield the lowest total lifecycle cost [1].

To perform a conductor optimization, numerous input variables must be defined including: 1) Physical characteristics of the transmission line, 2) Electrical properties of the conductor, 3) Cost Estimates of the T-lines that support different conductors, and 4) Financial variables from the client/utility.

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