Grid Integration Group
Energy Storage & Distributed Resources Division

Reconductoring Economic and Financial Analysis (REFA) Tool

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Summary

This documentation describes the Reconductoring Economic and Financial Analysis (REFA) tool. REFA helps transmission planners to understand financial and economic performance of line upgrade projects, using conventional or advanced conductor reconductoring solutions. The tool also allows utilities to demonstrate the entire lifetime value of reconductoring projects, supporting potential justifications for projects with higher CAPEX.

Background

Various tools are widely adopted by the electrical power industry for detailed transmission line design, such as PLS-CADD, Sag10, and ETAP. A missing piece is that those tools do not consider the economics and benefits of capacity upgrade projects as the choice of investment options is made during system-wide capacity expansion studies. In addition, no direct comparison between various types of conductors is possible using line design software.

The REFA tool considers technical and economic parameters for the evaluation of capacity upgrade projects. For a given transmission project, the tool selects a set of conductors that are technically feasible, considering industry standards for current-temperature and sag calculations. The model then presents the least-cost option for each conductor class, through a net-present value calculation over the lifetime of the project.

Conductor ampacity and temperature calculations are generally based on the IEEE 738 standard, while the graphical method is used for sag-tension calculations, which requires stress-elongation curves for different conductor types and sizes at multiple temperatures. As these curves are not readily available, we opt for the analytical method that allows for the calculation of tension and sag from temperature dependent formulas.

REFA Tool Description

The REFA tool runs a technico-economic analysis of a line upgrade project for different infrastructure investment options, including full rebuild, reconductoring, or voltage upgrade. The current version also incorporates the analysis of the existing conductor. In practice, for a given analysis, the user can:

- Specify the location of the line upgrade project, for the tool to retrieve basic line information from available geographic and transmission system data;
- Obtain a set of all feasible conductors for the specific project by using the standard temperature-ampacity and sag-tension calculations as constraints;
- Compare infrastructure investment options (such as reconductoring, rebuild, or voltage upgrade) for each project, considering the full net-present cost (NPC) of a project;
- Compare the economic performance of different conductor types (including both conventional and advanced conductors) for each investment option and identify least-cost solutions;
- Capture the value of advanced conductors under different conditions, including:
  - Technical project requirements (such as capacity or clearance);
  - Project applications (such as reconductoring or a rebuild);
  - Value streams (like cost of losses);
  - Economic parameters (e.g. cost of capital, project horizon).

- Evaluate the base case of keeping the existing conductor, which in some cases can cause congestion that is quantifiable in the tool.
- Consider optional capabilities: i) Check feasibility of conductors in terms of the corona effect; ii) Specify different types of structures, including the relationship between conductor weight and structure type.

Using the Tool

The user is requested to sign-up for an account at `refa-app.lbl.gov`, which allows to access the tool at `https://refa-app.lbl.gov/refa-application-access` and create projects (Fig. 1).

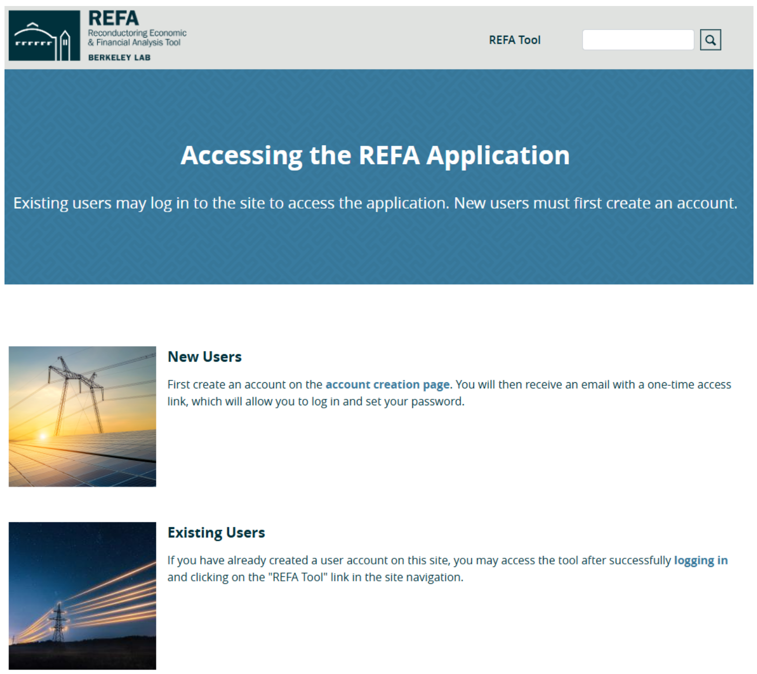


Figure 1: Accessing the REFA tool

When logged in, the user can access/delete projects created from earlier sessions or start a new project (Fig. 2).

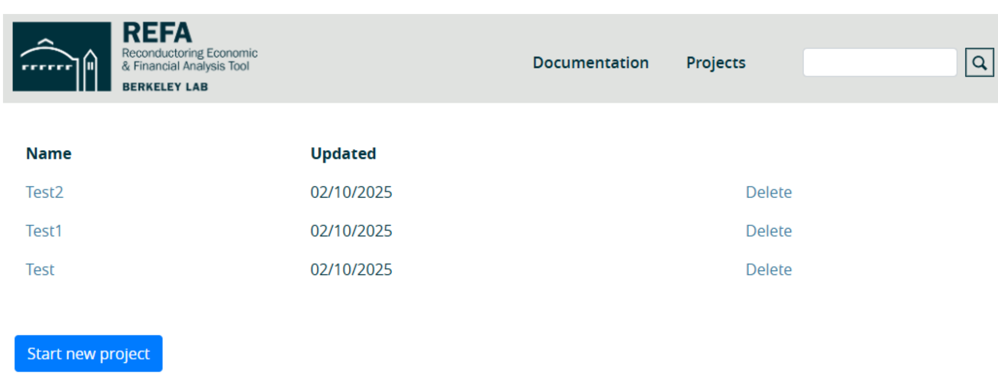


Figure 2: Managing REFA projects

Project creation page is shown in Fig. 3, asking for a project name, preferred system of units, and source of conductor parameters (default database or from an existing project).

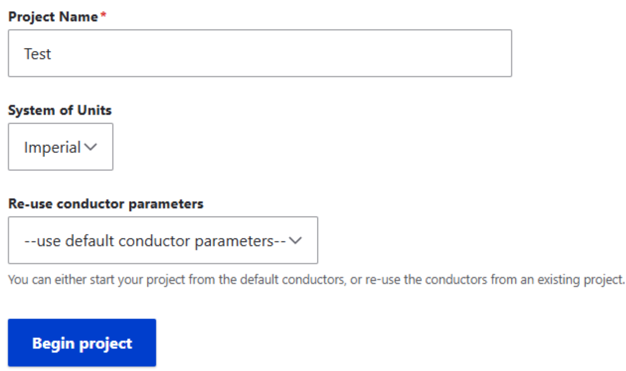


Figure 3: Creating a new project

Under the "Locate Project" section, the US state of the line project needs to be specified first, as shown in Fig. 4.

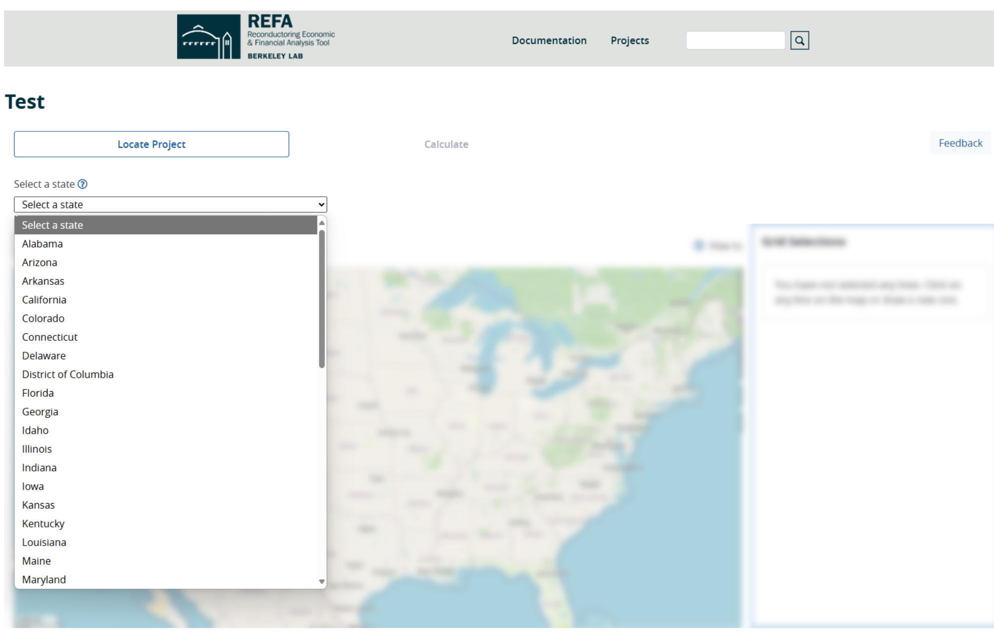


Figure 4: Choosing the state of the project

Next, using the interactive map displaying the transmission grid of the selected state, the user can select a line and/or draw the desired transmission line project. Only one line project can be selected before launching the analysis using the "Calculate" button. The length and location of the project will be taken from this step and used in calculations as described in later sections (Fig. 5).

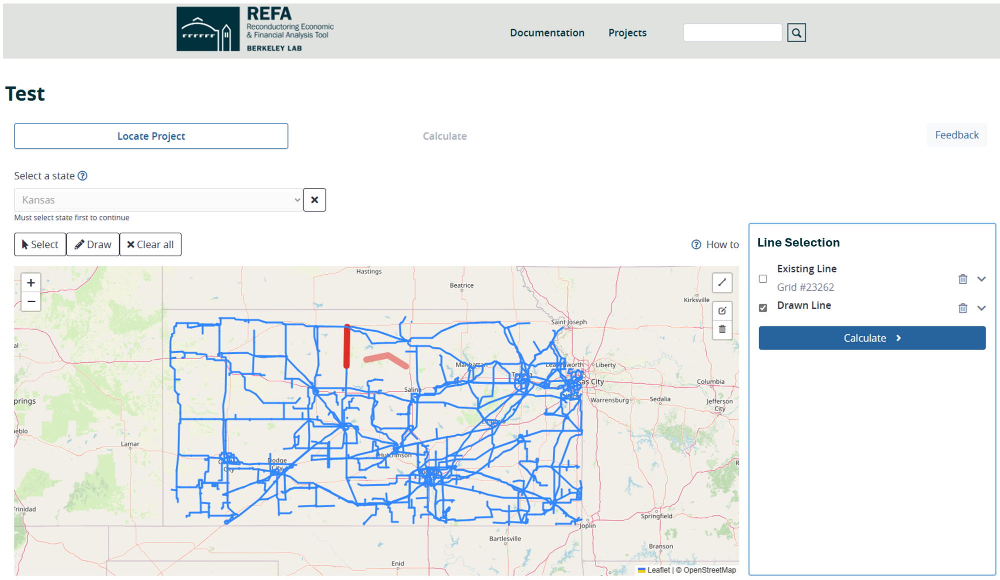


Figure 5: Locating the line project

Then, the user is taken to the "Calculate" section where project information can be entered as shown in Fig. 6 (typical default values are pre-set for all parameters).

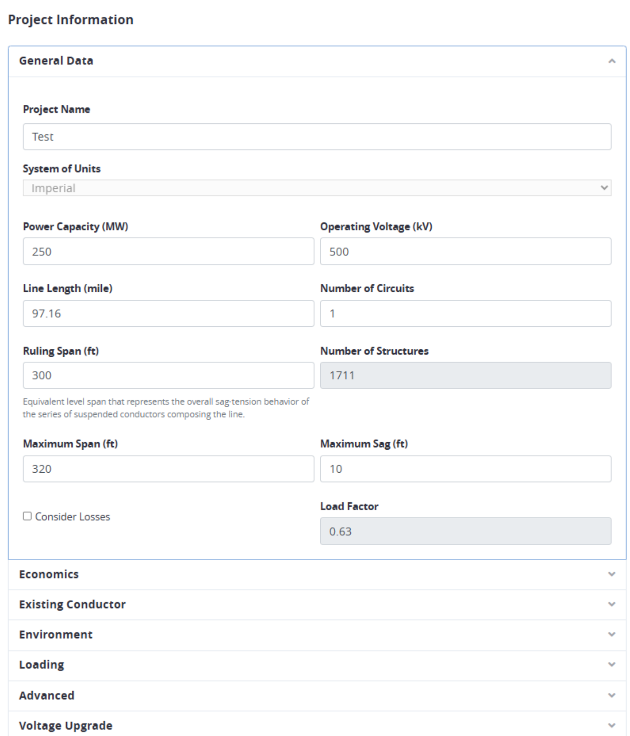
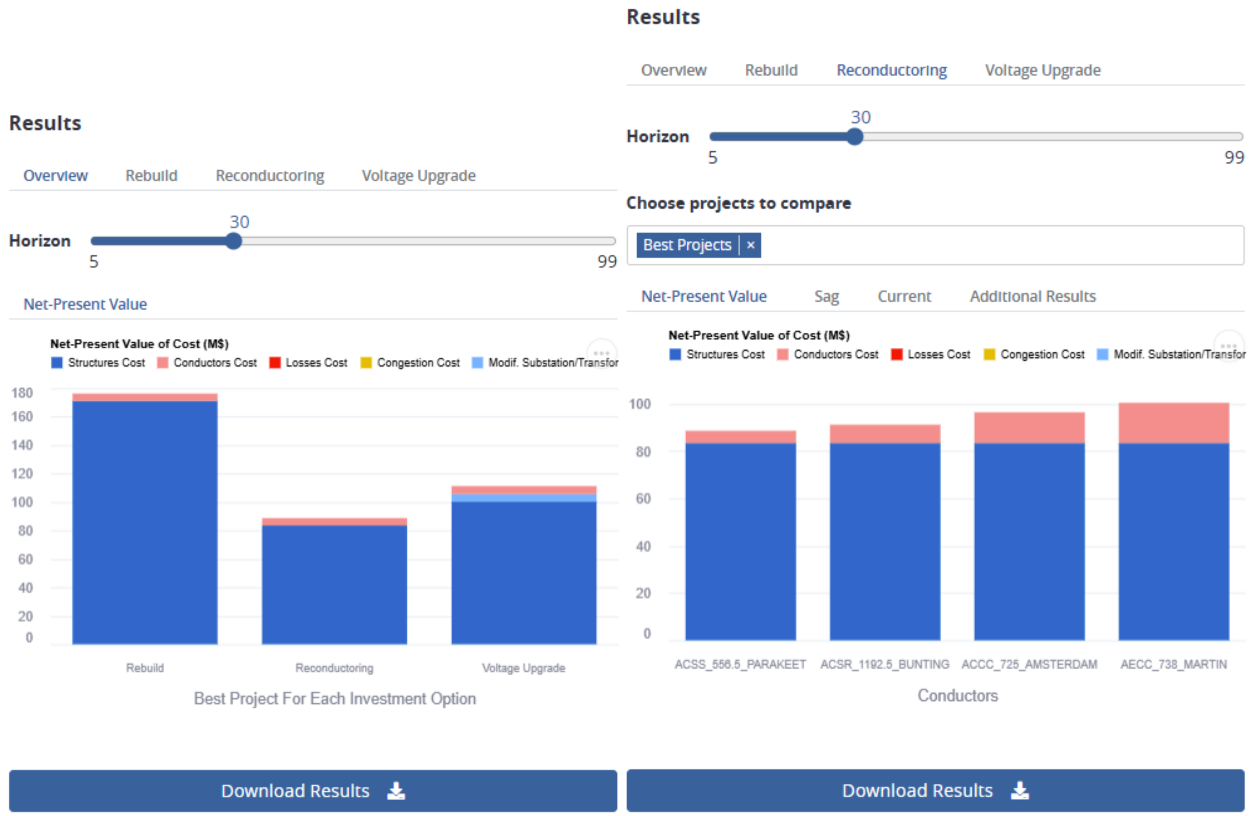


Figure 6: Specifying project information

Results are shown at the right-hand side of the page, with an overview tab that compares different investment options in terms of NPC (Fig. 7a), alongside a detailed tab for each investment option (rebuild, reconductoring, voltage upgrade) where sag and ampacity are shown in addition to the NPC (Fig. 7b).

Results can be downloaded from the tool as .csv files.



(a) Results overview

(b) Template of detailed results (reconductoring investment option)

Figure 7: Display of results in the REFA tool

When project information is complete or whenever a given parameters is modified, the analysis can be re-run by clicking the button "Calculate Results" to the right of Fig. 8.

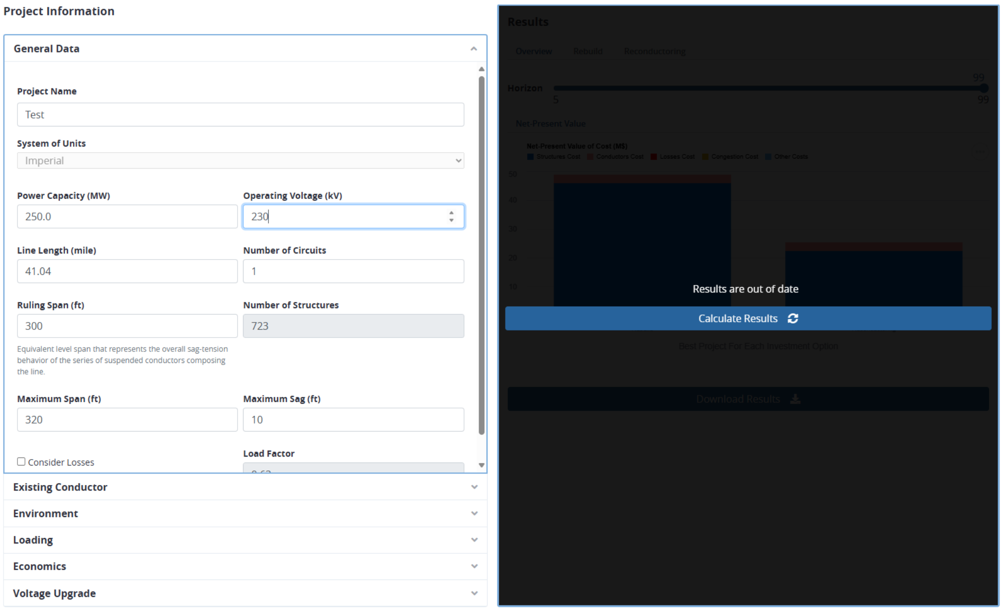
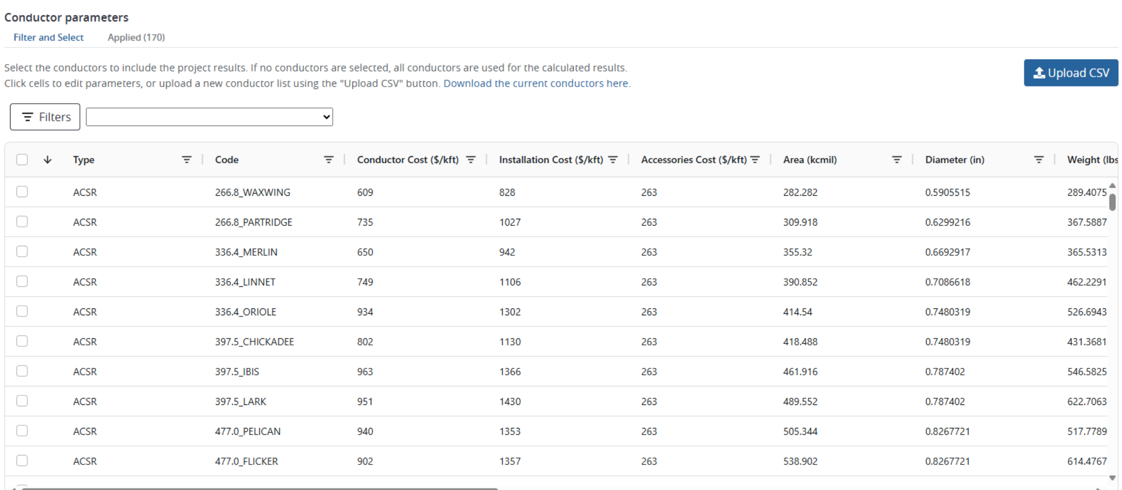


Figure 8: Updating results when parameters are modified

The database of conductors is provided at the bottom of the page, with the ability to select/deselect conductors from the analysis and filter different table columns (Fig. 9). The "Additional Results" tab shows results related to activating the optional capabilities of considering the corona effect and different types of structures. The user is able to download a template file of conductor parameters that can be modified to include new conductors, then upload the updated file to the REFA tool.



Type	Code	Conductor Cost ($/kft)	Installation Cost ($/kft)	Accessories Cost ($/kft)	Area (kcmil)	Diameter (in)	Weight (lbs
ACSR	266.8_WAXWING	609	828	263	282.282	0.5905515	289.4075
ACSR	266.8_PARTRIDGE	735	1027	263	309.918	0.6299216	367.5887
ACSR	336.4_MERLIN	650	942	263	355.32	0.6692917	365.5313
ACSR	336.4_LINNET	749	1106	263	390.852	0.7086618	462.2291
ACSR	336.4_ORIOLE	934	1302	263	414.54	0.7480319	526.6943
ACSR	397.5_CHICKADEE	802	1130	263	418.488	0.7480319	431.3681
ACSR	397.5_IBIS	963	1366	263	461.916	0.787402	546.5825
ACSR	397.5_LARK	951	1430	263	489.552	0.787402	622.7063
ACSR	477.0_PELICAN	940	1353	263	505.344	0.8267721	517.7789
ACSR	477.0_FLICKER	902	1357	263	538.902	0.8267721	614.4767

Figure 9: Database of conductors

1 Data Collection

The tool requires many parameters as inputs, either as conductor-specific input or project and installation environment-specific input.

Data from different sources are merged in an attempt to populate a comprehensive conductors database of different types, sizes, and manufacturers. The international system of units is used within the tool to handle all parameters, but an internal conversion is implemented in order to allow US utilities to configure the analysis if preferred using imperial system units in the interface.

As of version 1.0, three conductor related costs are considered: material cost (or acquisition cost), installation cost, and accessories cost. These are found for most ACSR and ACSS conductor sizes in reports like [1], then estimated for advanced conductors based on deployment examples and their proportions to the cost of conventional conductors of the same size [2]. The cost of accessories has the same value for all ACSR and ACSS conductors, and a different higher value for all advanced conductors

Conventional Conductors

1.1 Aluminum Conductor Steel Reinforced - ACSR

This is the most common conductor type used in the US transmission grid with a wide range of standardized sizes produced by many vendors. Various datasheets were collected, and the following steps were implemented for the final parameter selection:

- Use report [1] from the mid-continent independent system operator (MISO) to identify conductor sizes with associated costs;
- For each selected conductor, take all needed parameters from Priority Wire & Cable and Eland Cables datasheets;
- Fill in the fields for the coefficient of thermal expansion and elastic modulus from Gulf Cable and Trefinasa data, using the information about stranding.

1.2 Aluminum Conductor Steel Supported - ACSS

Since the 1970's, an increased interest in ACSS conductor led to a wide use in transmission lines. This conductor type is also standardized and produced by many manufacturers.

- The same conductor sizes from [1] are taken with their ACSS costs;
- For each selected conductor, take all needed parameters from Midal Cables datasheets;
- Complete the weight parameter for some conductors from APAR company data, and maximum ampacity from Southwire company;
- Use the standard rated tensile strength (RTS);
- In the absence of values for the coefficient of thermal expansion and elastic modulus, we assume that their values are only slightly different than that of ACSR conductors. ACSS conductors expand less with temperature (i.e. a lower coefficient of thermal expansion by 10%), and are less stiff than ACSR conductors that contain a steel core (i.e. lower elastic modulus by 10%).

Advanced Conductors

1.3 Aluminum Conductor Composite Core - ACCC

Most parameters are provided in CTC Global manufacturer datasheets. The elastic modulus and coefficient of thermal expansion were only found in documents from Midal Cables for two dozens of ACCC conductor sizes. Conductor costs are estimated by multiplying the cost of the closest ACSR conductor in size by a factor taken from Idaho National Lab report [2] (i.e. 2.5 to 3 times the cost of ACSR).

1.4 Aluminum Conductor Composite Reinforced - ACCR

All parameters could be taken from the 3M conductor manufacturer datasheet, except for costs which are estimated as 5.5 times the cost of ACSR conductors.

1.5 Aluminum Encapsulated Carbon Core - AECC

While most manufacturers only focus on one supply chain segment, TS Conductor is vertically integrated and builds their core in-house [2]. AECC conductor data were added from TS Conductor corporation datasheets. The area and conductor diameter are deduced from the provided conductor outer diameter in inches. The coefficient of thermal expansion values are set to be lower by 30% than equivalent ACSR sizes (closest by size).

Costs are estimated based on ACSR conductor costs, where the factor of multiplication is set to 6 for TS conductors.

1.6 Aluminum Conductor Composite Supported - ACCS

The data for this conductor type from Southwire are provided in the company's datasheets. The units are adjusted to the SI system used in the REFA tool. The coefficient of thermal expansion values are set to be lower by 25% than equivalent ACSR sizes (closest by size).

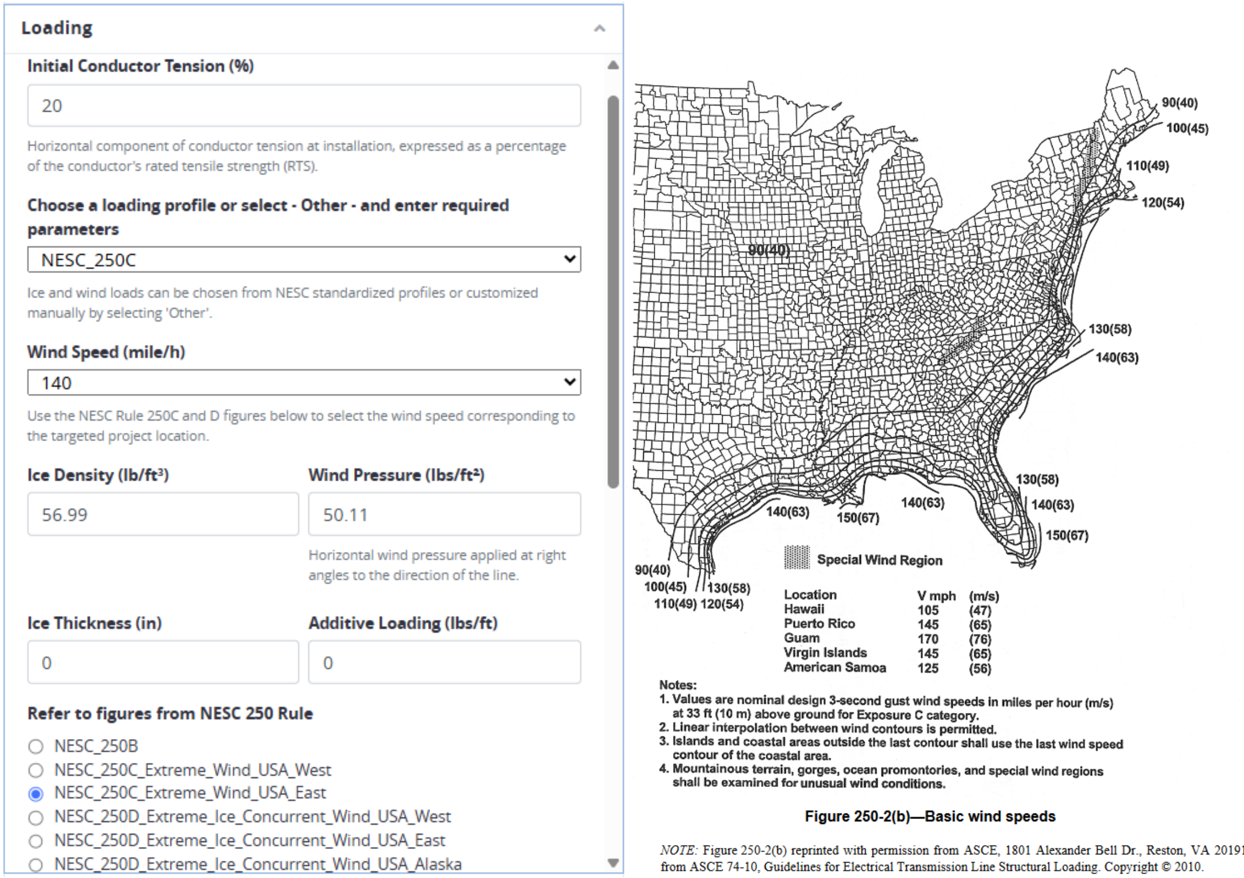
Costs are again estimated based on conventional conductor costs, where the values are multiplied by 5 for ACCS conductors.

1.7 Other Advanced Conductors

Some other conductors were explored, like C7 from Southwire and High Voltage Composite Reinforced Conductor (HVCRC) from Epsilon Cable, and could be integrated to the tool as soon as all required parameters are collected.

1.8 Conductor Loading

The behavior of line conductors is affected by weather conditions, which can be viewed as loads in case of ice and wind. We first integrate the loading of conductors in the REFA tool as specified by the national electrical safety code (NESC) rule 250B [3], where different loading profiles are proposed. Each profile corresponds to specific temperature, wind speed, and ice thickness, to represent various regions in the USA. NESC 250C and 250D are later integrated to the tool by allowing the user to set wind speed and ice thickness from the illustrative figures taken from [3] as shown in Figure 10.



(a) (b)

Figure 10: Specifying the loading Profile

The user is able to customize the loading information for any specific project location by manually specifying wind pressure, ice thickness, and additive loading.

2 Investment Options

The REFA tool aims to conduct a technico-economic analysis of transmission projects considering various investment options. The tool currently considers three investment options: rebuild, reconductoring, and voltage upgrade. Some of these options can be considered at once, like voltage upgrade during a rebuild. Table 1 and Figure 11 summarize the main assumptions of each investment option.

Table 1: Considered investment options and associated assumptions

	Rebuild	**Reconductoring**	**Rebuild + Voltage Upgrade**	**Reconductoring + Voltage Upgrade**	**Voltage Upgrade**
Structures	New	Keep Old	New	Keep Old	Keep Old
Conductors	New	New	New	New	Keep Old
Transformer and Substation Inv.	No	No	Yes	Yes	Yes

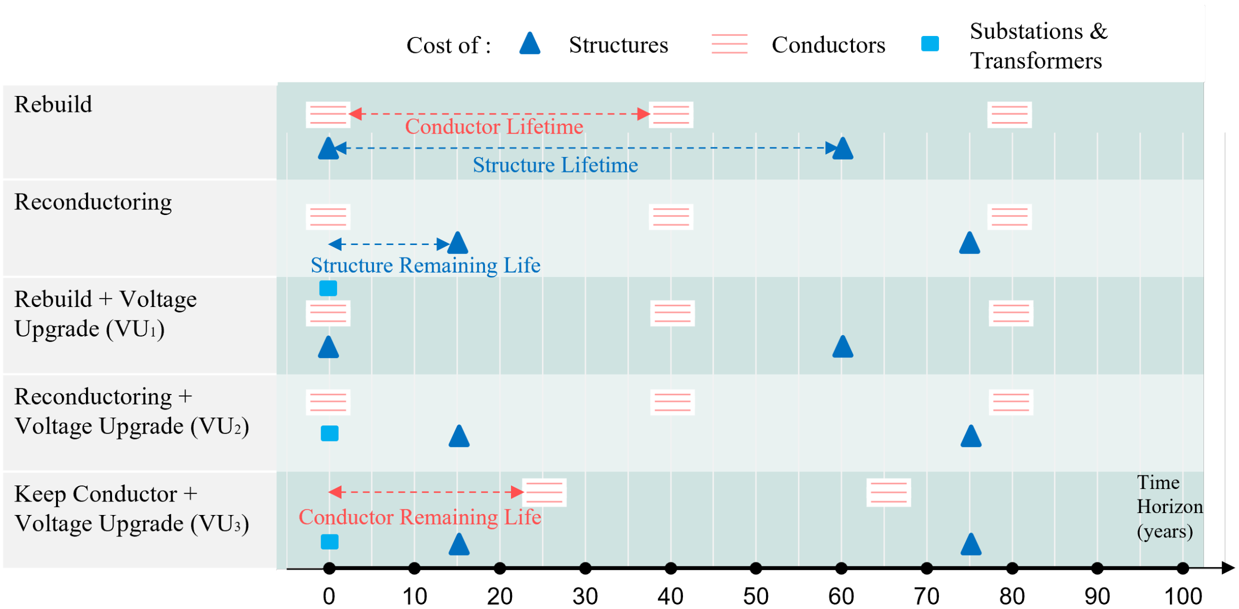


Figure 11: Considered investment options

2.1 Rebuild

Describes the case where a transmission line is partially or entirely reconstructed. This involves replacing structures, changing conductors (by advanced or regular conductors), and in some cases modifying substations and other grid components. It can be argued that the cost of conductors is negligible compared to other infrastructure costs suggesting the use of advanced conductors, but utilities do not seem to massively opt for advanced conductors for many reasons, e.g. lack of reconductoring demonstrations, difficulty to manipulate advanced conductors by technicians, absent regulatory incentives, etc.

2.2 Reconductoring

Reconductoring consists of replacing the existing conductors with new ones that relieve some constraints like sag and thermal heating. Supporting structures are usually kept, which considerably reduces the project costs. However, reconductoring is suited for specific lines that should be thoroughly identified.

2.3 Voltage Upgrade

Voltage upgrades enable the line to convey lower currents for the same power, which alleviates conductors ampacity requirements and reduces line power losses. Still, new challenges are introduced, like the need to redefine the vertical clearance, check the spacing between phases and circuits, as well as invest more in transformers and substations modifications.

2.3.1 Rebuild and Voltage Upgrade

In this case, a voltage upgrade is conducted while rebuilding a line by replacing structures and conductors. The upfront cost is set to be higher than rebuild-only, but the project can benefit from the reduced losses given higher operating voltages over the line lifetime.

2.3.2 Reconductoring and Voltage Upgrade

In specific settings, the voltage upgrade can be performed keeping the same structures, while conductors may be replaced. Modifications in transformers and substations are still needed, as well as some upgrades in the structures, such as making conductor attachments higher, uplifting structures, changing insulators, modifying cross-arms, etc.

Many international projects are reported to use aforementioned structure enhancements for voltage upgrade. Structure extensions are detailed in Cigre TB 353 [4] for projects in the USA, Canada, Brazil, and Norway. Other examples are introduced in [5, 6, 7, 8].

2.3.3 Keeping Existing Line and Voltage Upgrade

When the existing conductor is known, an interesting case is to evaluate the performance of keeping that conductor and the old structures, while upgrading the voltage. Aforementioned costs associated with voltage upgrade are considered.

3 Current-Sag Calculations

The REFA tool compares rebuilding, reconductoring, and upgrading voltage of a line using any conductor from the constructed database, and presents the best cost-effective options in terms of net-present cost. This is preceded by an initial step of checking all conductors for two constraints: ampacity and sag; to eliminate those which do not satisfy these two requirements from the transmission line projects.

Table 2: Parameters for current-temperature calculations

Parameter	**Description**
mC_p (J/(m .°C))	Total heat capacity of conductor
d (m)	Outside diameter of conductor
ρ_f (kg/m^3)	Density of air
v_w (m/s)	Speed of air stream at conductor
ϕ (°)	Angle between wind and axis of conductor
T_a (°C)	Ambient temperature
H_e (m)	Elevation of conductor above sea level
n	Day of the year
Lat (°)	Degrees of latitude
C_s (°)	Solar azimuth constant

3.1 Current-Temperature Calculations

Evaluation of current and temperature is based on the latest IEEE 738-2023 standard for bare overhead conductors [9].

1. The load current is defined in Eq. (1), where P is the line power capacity and V the operating voltage of the line.
$$I_{peak} = \frac{P}{V \cdot \sqrt{3}} \tag{1}$$
2. Given steady state weather conditions, conductor characteristics, and conductor maximum temperature T_c^{max}, the steady-state rating I (or ampacity) is calculated by rearranging the heat balance equation in (3) into Eq. (4). **The temperature at which ampacity is calculated for each conductor can be adjusted in the conductor database by setting the parameter "Maximum Temperature (Cel)" to the desired value**.

The radial thermal gradient that describes the temperature difference between the conductor surface and its core is not considered (as the thermal conductivity of collected conductors is not provided), thus omitting the need to define a conductor surface temperature T_s and a core temperature T_{core}. Equation (3) is obtained (when $dT_c = 0$) from the expression of the time-varying heat balance in Eq. (2)

$$I^2 \cdot R(T_c) + q_s - q_c - q_r = mC_p \cdot \frac{dT_c}{dt} \tag{2}$$

$$q_c + q_r = q_s + I^2 \cdot R(T_c^{max}) \tag{3}$$

$$I = \sqrt{\frac{q_c + q_r - q_s}{R(T_c^{max})}} \tag{4}$$

where $R(T_c)$ is the conductor resistance at temperature T_c, q_s the heat gain from solar radiation, q_c the convection heat loss, and q_r the radiation heat loss.

- Convection heat loss (q_c)
  Convection contains a forced and a natural component, where the former occurs with a given wind speed and the latter only at the no wind condition.
  For natural convection, the heat loss is given by Eq. (5);

$$q_{cn} = 3.645 \cdot \rho_f^{0.5} \cdot d^{0.75} \cdot (T_c - T_a)^{1.25} \qquad [W/m] \tag{5}$$

  The forced convection loss is expressed in equations (6) and (7) for low and high wind profiles, respectively;

$$q_{c1} = K_{angle} \cdot \left(1.01 + 1.35 \cdot N_{Re}^{0.52}\right) \cdot k_f \cdot (T_c - T_a) \qquad [W/m] \tag{6}$$

$$q_{c2} = K_{angle} \cdot 0.754 \cdot N_{Re}^{0.6} \cdot k_f \cdot (T_c - T_a) \qquad [W/m] \tag{7}$$

  where the wind direction factor K_{angle}, the dimensionless Reynolds number N_{Re}, the mean film temperature of the conductor boundary layer T_{film}, as well as the air dynamic viscosity μ_f, density ρ_f, and thermal conductivity k_f are calculated using equations (8)-(13);

$$K_{angle} = 1.194 - \cos(\phi) + 0.194 \cdot \cos(2\phi) + 0.368 \cdot \sin(2\phi) \tag{8}$$

$$N_{Re} = \frac{d \cdot \rho_f \cdot v_w}{\mu_f} \tag{9}$$

$$T_{film} = \frac{T_c + T_a}{2} \tag{10}$$

$$\mu_f = \frac{1.458 \cdot 10^{-6} \cdot (T_{film} + 273)^{1.5}}{T_{film} + 383.4} \qquad [kg/m.s] \tag{11}$$

$$\rho_f = \frac{1.293 - 1.525 \cdot 10^{-4} \cdot H_e + 6.379 \cdot 10^{-9} \cdot H_e^2}{1 + 0.00367 \cdot T_{film}} \qquad [kg/m^3] \tag{12}$$

$$k_f = 2.424 \cdot 10^{-2} + 7.477 \cdot 10^{-5} \cdot T_{film} - 4.407 \cdot 10^{-9} \cdot T_{film}^2 \qquad [W/m.^\circ C] \tag{13}$$

  The convection heat loss is finally set to the maximum between forced and natural convection (Eq. (14));

$$q_c = \max(q_{cn}, q_{c1}, q_{c2}) \tag{14}$$

- Radiated heat loss (q_r)
  The ambient temperature and conductor parameters of emissivity ϵ, diameter D, and temperature T_c are used to compute the radiated heat loss in Eq. (15);

$$q_r = 17.8 \cdot D \cdot \epsilon \left[\left(\frac{T_c + 273}{10}\right)^4 - \left(\frac{T_a + 273}{100}\right)^4 \right] \qquad [W/m] \tag{15}$$

- Solar heat gain (q_s)
  The energy delivered to the conductor from the sun is determined based on conductor characteristics (i.e. absorptivity α, projected area $A^{'}$) the total delivered heat from the sun adjusted for elevation at a specific date, time, and location Q_{se}, and the angle of incidence of the sun to the conductor θ as given by equations (16) and (17);

$$q_s = \alpha \cdot Q_{se} \cdot \sin(\theta) \cdot A' \qquad [W/m] \tag{16}$$

$$\theta = \arccos[\cos(H_c) \cdot \cos(Z_c - Z_l)] \tag{17}$$

  where parameters of hour angle ω, solar altitude H_c, solar declination δ, azimuth of sun Z_c, solar/sky radiated heat intensity Q_s, and elevation-corrected solar/sky radiated heat intensity Q_{se} are expressed in equations (18)-(25), with further details in [9] where all relevant parameters and coefficients ($Z_l, H_e, C_s, A, B, C, D, E, F$, and G) are provided;

$$\omega = (Time - Noon) \cdot 15° \qquad [°] \tag{18}$$

$$H_c = \arcsin\left[\cos(Lat) \cdot \cos(\delta) \cdot \cos(\omega) + \sin(Lat) \cdot \sin(\delta)\right] \tag{19}$$

$$\delta = 23.45 \cdot \sin\left[\frac{284 + n}{365} \cdot 360\right] \qquad [°] \tag{20}$$

$$Z_c = C_s + \arctan(\chi) \qquad [°] \tag{21}$$

$$\chi = \frac{\sin(\omega)}{\sin(Lat) \cdot \cos(\omega) - \cos(Lat) \cdot \tan(\delta)} \tag{22}$$

$$Q_s = A + B \cdot H_c + C \cdot H_c^2 + D \cdot H_c^3 + E \cdot H_c^4 + F \cdot H_c^5 + G \cdot H_c^6 \tag{23}$$

$$K_{solar} = 1 + 1.148 \cdot 10^{-4} \cdot H_e - 1.108 \cdot 10^{-8} \cdot H_e^2 \tag{24}$$

$$Q_{se} = K_{solar} \cdot Q_s \tag{25}$$

- Conductor resistance ($R(T_c)$)
  The electrical resistance is calculated as a function of conductor temperature using a linear interpolation from the representation of resistance in terms of temperature, given by Eq. (26)

$$R(T_c) = \left[\frac{R(T_{high)} - R(T_{low})}{T_{high} - T_{low}}\right] \cdot (T_c - T_{low}) + R(T_{low}) \tag{26}$$

3. A condition is added to eliminate from the analysis conductors with a thermal rating (ampacity) less or three times greater than the load current I_{peak}.

4. The temperature T and resistance per length R^l of each selected conductor are calculated given the load current I_{peak}. This can be achieved using Eq. (3) where convection and radiation losses are not linearly dependent on the conductor temperature. As a result, the iteration process described in [9] is implemented here using a binary search to get the temperature and resistance values;

   - The solar heat input to the conductor q_s is calculated (as it is independent of conductor temperature) using Eq. (16);
   - A trial conductor temperature is assumed T_{test};
   - The conductor resistance at T_{test} is calculated using Eq. (26);
   - The convection and radiation heat loss terms are calculated for T_{test} based on equations (5)-(15);
   - The current corresponding to the temperature T_{test} is calculated by means of the heat balance in Eq. (3);
   - The resulting current I_{result} is compared to the load current I_{peak} introduced in Eq. (1);
   - The temperature T_{max} is set to T_{test} if $I_{result} > I_{peak}$ or T_{min} set to T_{test} if $I_{result} < I_{peak}$;
   - The iteration is carried on with an update $T_{test} = \frac{T_{max}+T_{min}}{2}$ until the calculated current equals the peak current I_{peak} within a user-specified threshold.

3.2 Sag-Tension Calculations

The graphical method from Cigré technical brochure 324 [10] was recommended for use, but the unavailability of stress-elongation curves stirred the choice towards the iterative analytical calculations. Guidelines are provided in [10], and an algorithm is detailed in [11], which is implemented in this work to calculate the sag after loading, as described in algorithm 1.

Algorithm 1 Sag calculations

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1. Load conductor parameters : cross sectional area A, diameter d, initial weight W_0, elastic modulus E, coefficient of thermal expansion α
2. Initialize project conditions : span S, initial tension H_0, and initial temperature T_0
3. Calculate the initial sag D_0 and length L_0 :
   $D_0 = \frac{H_0}{W_0} \cdot \left(\cosh(\frac{W_0 \cdot S}{2 \cdot H_0}) - 1\right), \quad L_0 = S + 8 \cdot \frac{D_0^2}{3 \cdot S}$
4. Use loading parameters (wind + ice) to calculate the new weight W_1
   $W_1 = \sqrt{(W_0 + W_{ice})^2 + W_{wind}^2}$
5. Find the initial length L_{ref} of the conductor as L_0 is only valid at a given reference temperature
   $L_{ref} = L_0 \cdot \left(1 - \frac{H_0}{E \cdot A}\right)$
6. Use the steady-state conductor temperature T_1 (calculated in Sec. 3.1) to estimate the new conductor length based on temperature difference
   $L_{temp} = L_{ref} \cdot (1 + \alpha \cdot (T_1 - T_0))$
7. Initialize: temporary variables $D^{'} = 0$ and $H_1^{'} = H_1$, and tension limits $H_1^{high} = 200000$ and $H_1^{low} = 0$

while ($|D_1 - D^{'}| > 0.001$) **do**

- $H_1 = \frac{H_1^{high} + H_1^{low}}{2}$
- $H_1^{'} \leftarrow H_1$, $D^{'} \leftarrow D_1$
- Update: $L_1 = L_{temp} \cdot (1 + \frac{H_1}{E \cdot A})$ and $D_1 = \sqrt{\frac{3 \cdot S \cdot (L_1 - S)}{8}}$
- Calculate the new tension $H_1 = \frac{W_1 \cdot S^2}{8 \cdot D_1}$
- if $H_1 > H_1^{'}$ then $H_1^{min} = H_1^{'}$, else $H_1^{max} = H_1^{'}$

end while

8. The iterations converge to a value for the sag D_1

The plastic elongation and long-term creep are not considered in REFA v1.0 as the main focus is to demonstrate how the technical calculations can be included in cost-benefit analyzes of investment projects. Sag calculations can be easily extended to include more details and is expected to not affect the performance of the proposed approach [12].

4 Economic Analysis

Once the feasible conductors in terms of sag and ampacity are selected, the cost-benefit evaluation of each conductor choice is carried out by calculating the NPC over a specified time horizon. The NPC (conductor, structure, and losses cost) is used in this analysis to determine the value of each line upgrade project. The main inputs to this procedure are summarized in Table 3.

4.1 Net-Present Cost Calculations

Line structures and conductors are used in the grid for a defined lifetime before replacement. As such, even if structures and conductors are not replaced at the time of project evaluation ($y = 0$), there should be an investment when the lifetime ends. It is assumed that all structures of a line are replaced at the same time, which also applies for conductors with a different lifetime. All costs are computed at a yearly basis.

Table 3: Main input parameters to NPC calculations

Parameter	Description
$C^{cd,aq}$ (\$/km)	Cost per unit length of acquiring the conductor (material cost)
$C^{cd,inst}$ (\$/km)	Cost per unit length of installation
$C^{cd,acc}$ (\$/km)	Cost per unit length of needed accessories for conductor installation
$C^{st,u}$ (\$)	Cost of a new structure
$C^{st,upgd}$ (\$)	Cost of upgrading a structure
$C^{dol,MWh}$ (\$/MWh)	Cost of energy
L^{line} (km)	The length of the transmission line
N^{st}	Number of structures composing the transmission line
Structure lifetime (years)	The duration of structure use in the system
Conductor lifetime (years)	The duration of conductor use in the system

$$C_y^{st} = C^{st,u} \cdot N^{st} \cdot IF_y \tag{27}$$

$$C_y^{cd} = \left(C^{cd,aq} + C^{cd,inst} + C^{cd,acc}\right) \cdot L^{line} \cdot IF_y \cdot N \tag{28}$$

$$IF_y = (1+f) \cdot IF_{y-1} \tag{29}$$

Equation 27 depicts the cost of investment in structures C_y^{st}, which considers the cost per unit structure $C^{st,u}$ and the number of structures N^{st}; while Eq. (28) shows the conductor investment C_y^{cd} broken down into conductor costs (conductor acquisition $C^{cd,aq}$, installation $C^{cd,inst}$, and accessories $C^{cd,acc}$), multiplied by the length of the line L^{line} and the total number of conductors N ($N = \cdot N^{cd} \cdot N^{ph} \cdot N^{ckt}$, with N^{cd} the number of conductor per phase (or DC pole), N^{ph} the number of phases (or DC poles) per circuit, and N^{ckt} the number of circuits). An inflation factor IF_y from Eq. (29) is included in both cost calculations to account for the annual inflation f.

$$C_y^{ls} = En^{ls} \cdot C^{dol,MWh} \cdot IF_y \cdot L^{line} \cdot 10^{-6} \tag{30}$$

$$En^{ls} = R^l \cdot I_{peak}^2 \cdot LLF \cdot 8760 \cdot N \tag{31}$$

$$LLF = 0.3 \cdot LF + 0.7 \cdot LF^2 \tag{32}$$

Power losses can be incorporated in cost calculations to better inform investment decision-making, which relies currently on evaluating upfront capital investments only. The cost is calculated as the dollar cost of a MWh loss at each conductor $C^{dol,MWh}$ factored by the annual energy loss En^{ls}, the inflation factor IF_y, and the line length L^{line}, as shown in Eq. (30).

The annual energy losses (i.e. 8760 hours) are shown in Eq. 31 for a 3-phase line in $Watts.h/m$, where R_l is the calculated resistance per length in Ohm/m, N^{ckt} the number of circuits in the line, and LLF the loss of load factor obtained by (32) using the load factor $LF = AverageDemand/PeakDemand$ [13]. Coefficients for the loss factor equation have been empirically determined for North American markets (0.3 and 0.7 for transmission, and 0.15 and 0.85 for distribution), but vary by region [14].

$$NPC_y = \left(C_y^{st} + C_y^{cd} + C_y^{ls}\right) \cdot \frac{1}{(1+WACC)^y} \tag{33}$$

The cost of a line project (or the net-present cost) at a given year NPC_y can be then calculated as in Eq. (33) by multiplying the sum of costs (costs of conductors, structures, and losses) by the cost of capital over the considered horizon of time, where WACC is the weighted average cost of capital, and y is the time of cost evaluation. The final NPC is deduced as the cumulative sum of NPC^y over a defined horizon (line lifetime, e.g. 100 years).

The NPC is calculated for all feasible conductors given investment options discussed above, which differ in their associated assumptions. Rebuilding a line involves replacing the structures and possibly the conductors, while reconductoring focuses on changing conductors. Voltage upgrade is combined with rebuild and reconductoring actions with slight changes in calculations that are discussed in Sec. 4.2. REFA v1.0 introduces the analysis of the existing conductor, which adds to the base analysis over all conductors.

4.1.1 Rebuild

Both structures and conductors are replaced during a line rebuild. This translates to replacing some structures even if their lifetime did not end. Both structure cost C^{st} and conductor cost C^{cd} include an initial investment at $y = 0$, then subsequent investments at the end of life of structures (e.g. 40 years) and conductors (e.g. 60 years), all calculated through equations (27) and (28).

4.1.2 Reconductoring

Only conductors are replaced in this case as the structures are kept for their remaining lifetime. As such, C^{cd} is committed right at $y = 0$, while C^{st} is incurred at the end of life of existing structures (no C^{st} when structure remaining lifetime > 0). Costs are again calculated by equations (27) and (28) at each end of life of structures and conductors.

4.2 Voltage Upgrade Calculations

A project where the voltage is increased, will decrease the line current, meaning that there may be conductor types that are not feasible for the initial voltage level, which become feasible for the upgraded voltage. The new voltage level $V^{'}$ is used in Eq. (34) to calculate the peak current $I^{'}_{peak}$, which serves in subsequent current-temperature and sag-tension calculations to select the feasible conductors.

$$I^{'}_{peak} = \frac{P}{V' \cdot \sqrt{3}} \tag{34}$$

The ampacity and sag calculations are implemented to run separately for each investment option, which allows to take into account the voltage level increase in case of voltage upgrade projects, while maintaining the nominal voltage for other projects. Note that the clearance and phase-spacing requirements also change with voltage upgrade, thus the standardized values related to each voltage level can be used in the tool (like the general order 95 from the california public utilities commission [15, 16]).

The project cost calculations are similar to equations (27)-(33), except for some additional costs of needed modifications in structures, substations, and transformers for the voltage upgrade, which are aggregated into a cost C^{upgd} at $y = 0$ as shown in Eq. (35). This cost varies depending on the chosen case from Sec. 4.2.

$$NPC_0 = C_0^{st} + C_0^{cd} + C_0^{ls} + C^{upgd} \tag{35}$$

4.2.1 Rebuild and Voltage Upgrade

Rebuilding a line can be an opportunity to upgrade the voltage. Despite increasing upfront costs, this can reduce the lifetime cost of the project by considerably reducing line losses. The cost C^{upgd} can be specified as an aggregate value, or composed as in Eq. (36) from the unitary cost of adding/modifying a substation C^{ss} times the number of affected substations N^{ss}, and the unitary cost of adding/modifying a transformer C^{tf} multiplied by the number of affected transformers N^{tf}.

$$C^{upgd} = C^{ss} \cdot N^{ss} + C^{tf} \cdot N^{tf} \tag{36}$$

4.2.2 Reconductoring and Voltage Upgrade

Some line upgrade projects consider keeping the same structures and increase the voltage (no need for C^{st} in Eq. (37)). The conductors may be changed, where the evaluation in this case over all considered conductors to identify the best choices. The cost C^{upgd} includes substation and transformer costs, as well as possible upgrade to structures like setting attachments higher, uplifting structures, changing insulators, modifying cross-arms, etc. [17]. This is captured in Eq. (38) by incorporating the cost of upgrading a structure $C^{st,upgd}$ times the number structures. We assume that all structures are upgraded in this case by using N^{st}, but there may be only a need to upgrade some structures along the line corridor.

$$NPC_0 = C_0^{cd} + C_0^{ls} + C^{upgd} \tag{37}$$

$$C^{upgd} = C^{ss} \cdot N^{ss} + C^{tf} \cdot N^{tf} + C^{st,upgd} \cdot N^{st} \tag{38}$$

4.2.3 Keeping Existing Line and Voltage Upgrade

An existing conductor can also be kept alongside the structures, making only changes related to voltage upgrade. This option is expected to be the most cost effective given the limited upfront investments NPC_0 in Eq. (39), but it is only applicable in niche situations. The cost C^{upgd} in Eq. (40) includes structure, substation, and transformer upgrade costs.

$$NPC_0 = C_0^{ls} + C^{upgd} \tag{39}$$

$$C^{upgd} = C^{ss} \cdot N^{ss} + C^{tf} \cdot N^{tf} + C^{st,upgd} \cdot N^{st} \tag{40}$$

4.3 Considering The Existing Conductor

A practical approach to line investment evaluation is to compare the existing layout (specifically conductor type) with other possible options. For an existing conductor, given the line voltage V and a computed conductor ampacity I_{peak}^{E} (using calculations in Sec. 3.1), the power transiting on the existing line is:

$$P^E = I_{peak}^{E} \cdot V \cdot \sqrt{3} \tag{41}$$

In case the specified line power P exceeds the maximum power allowed by the existing conductor P^E, a congestion cost would be incurred. Total marginal cost of congestions ($C^{dol,cg}$ in \$/MWh) can be approximated, for example, by the difference in locational marginal prices (LMPs) in adjacent nodes [18]. This cost can then be applied to the energy that has to be re-routed to other lines (at higher costs) due to the congestion, which can be approximated by the triangular shape of the load duration curve, shown in Figure 12 and described by Eq. (42).

$$p(x) = P - \frac{P}{T} \cdot x \tag{42}$$

$$t^{E}_{|p(x)=P^E} = \frac{P - P^E}{P} \cdot T \tag{43}$$

Congestion costs arise when, in order to respect transmission constraints, some higher-cost generation is dispatched in favor of lower-cost generation that would otherwise be used (in the absence of the constraint) [19]. The congestion energy can be quantified by determining the portion of time during which congestion happens t^E from equations (42)-(43). Then, the annual ($T = 1y = 8760h$) congestion cost is proportional to the congestion energy shown in Fig. 12 and formulated in Eq. 44, where $C^{dol,cg}$ is the marginal cost of congestion, and congestion energy is shown in Fig. 12.

$$C_y^{cg} = \frac{\left(P - P^E\right) \cdot t^E}{2} \cdot C^{dol,cg} \cdot IF_y \tag{44}$$

Line losses are calculated in Eq. (45), where the current attains the maximum conductor ampacity I_{peak}^{E} during congestion periods, and the cost $C^{dol,MWh}$ may change from the value used at nominal conditions (Eq. (30)). In a congested line (with line resistance R^E), losses are expressed as the sum of losses in that line and the losses caused by the congestion power that is picked up by another adjacent. The resistance of

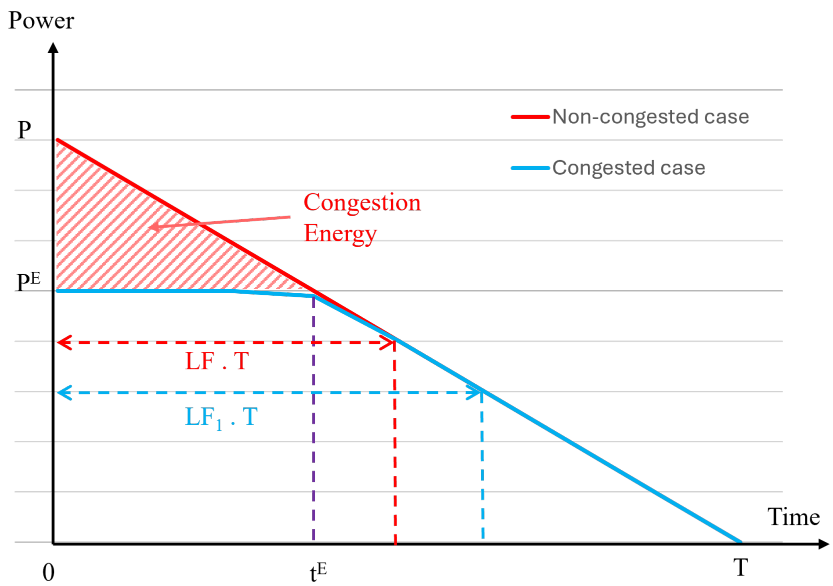

Figure 12: Estimation of congestion costs

the adjacent line is chosen to equal that of a line with an ACSR DRAKE conductor at $75°C$, which is one of the most used conductor types in the transmission grid. The loss factor LLF_1 is computed from Eq. (32) using the updated load factor LF_1 in Eq. (46), and the LLF is taken from Eq. (32).

$$C_y^{loss,cg} = \left[R^E \cdot (I_{peak}^E)^2 \cdot LLF_1 + R^l \cdot (I_{peak} - I_{peak}^E)^2 \cdot LLF\right] \cdot 8760 \cdot N \cdot C^{dol,MWh} \cdot IF_y \cdot L^{line} \tag{45}$$

$$\begin{aligned} LF_1 &= \frac{\left(T + t^E\right) \cdot P^E/2}{P^E \cdot T} \\ &= \frac{T + t^E}{2 \cdot T} \end{aligned} \tag{46}$$

The project cost calculation is updated accordingly to include congestion costs.

$$NPC_y = \begin{cases} \left(C_y^{st} + C_y^{cd} + C_y^{ls}\right) \cdot \frac{1}{(1+WACC)^y} & if \quad P - P^E \leq 0 \\ \left(C_y^{st} + C_y^{cd} + C_y^{loss,cg} + C_y^{cg}\right) \cdot \frac{1}{(1+WACC)^y} & if \quad P - P^E > 0 \end{cases} \tag{47}$$

Similar to Eq. (41), the power for each candidate conductor is deduced from current calculations (Sec. 3.1) to select only those conductors which do not result in congestion. The sag requirement is also checked, choosing only feasible conductors. The NPC is computed for the feasible conductors using equations (27)-(33), then displayed in the results alongside the existing conductor's NPC.

5 Structure Types

Structures can be of different types depending on the loading forces they bear and location within the line. We distinguish:

- Tangent structures (suspension structures): are the most commonly used structures where the transmission line angle is between 0° and 2°.
- Running angle structures: are used where the line alignment changes direction and the line angle is between 2° and 45°.

- Non-Angled deadend structures: are partial deadend structures and not designed for full terminal loads and the line angle is between 5° to 45°. They are designed to withstand some unbalanced wire tensions in one direction of one or all wires on one face of the structure.
- Angled deadend structures: are designed for full terminal loads for all wires and the line angle is between 0° and 90°.

Costs of each structure type is collected from [1] for various voltage levels. These are integrated to the tool as illustrated in Figure 13, where the user can specify the number of structures per-type and their material/geometry (e.g steel pole, wood pole, steel tower, etc.) to get the associated cost, which also depends on the structure height. The final structure cost used in economic calculations is deduced as a weighted average of all types costs considering their respective proportions within the total number of structures. The line angle should be specified for the extreme case for which loading forces need to be evaluated.

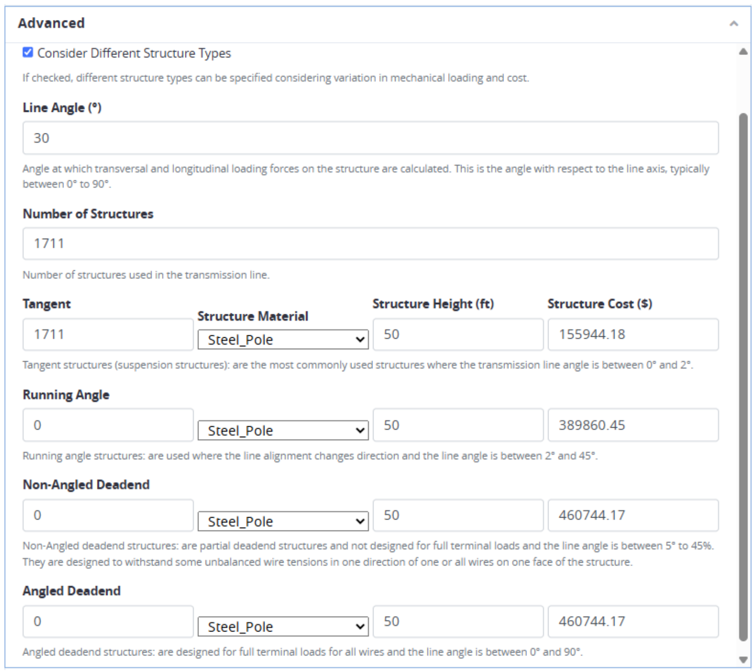

Figure 13: Setting the proportions of structure types

The unit cost of structure for use in economic calculations is calculated based on Eq. (48), where St is the set of structure types (i.e. tangent, running angle, non-angled deadend, and deadend), N^{st} is the total number of structures, $N^{st,s}$ is the number of structures of type s, and $C^{st,s}$ is the unit cost of a structure of type s.

$$C^{st,u} = \frac{\sum_{s \in St} N^{st,s} \cdot C^{st,s}}{N^{st}} \qquad [\$] \tag{48}$$

6 Link Structure Cost to Conductor Size

The conductor size defines the forces applied at the structures, possibly leading to more investment on foundation and structure strength in order to support vertical, transverse, and longitudinal loading forces. Consequently, the calculation for structure cost is modified as follows:

- Define a typical height h^t for each reference structure cost $C^{st,u}$ collected from [1]. Then, when a user specifies a structure type and a height h, the structure unit cost $C^{st,u}$ is adjusted for each structure type, multiplying by $\frac{h}{h^t}$.

- Calculate the vertical, transverse, and longitudinal loading forces that each conductor applies in a structure.

  The vertical load from conductors affects the longitudinal tensional force at the structure. The total conductor weight W_1 is expressed in Eq. (49), where W_0 is the weight per unit length of the conductor, W_{ice} is the weight of the ice load given by Eq. (50), and W_{wind} is the weight due to wind load given by Eq. (51), ρ is the ice density, d is the conductor diameter, Δ_{ice} is the ice thickness, g is the acceleration due to gravity ($= 9.8m/s^2$), and p_{wind} is the wind pressure.

$$W_1 = \sqrt{(W_0 + W_{ice})^2 + W_{wind}^2} \qquad [N/m] \tag{49}$$

$$W_{ice} = \rho \cdot \pi \cdot \frac{(d + 2 \cdot \Delta_{ice})^2 - d^2}{4} \cdot g \qquad [N/m] \tag{50}$$

$$W_{wind} = p_{wind} \cdot (d + 2 \cdot \Delta_{ice}) \qquad [N/m] \tag{51}$$

  W_1 is used in sag calculations to get the conductor tension at mid-span H_1 (Section 3.2). The conductor tension in a level span varies from a minimum value at mid-span H_1 [20] to a maximum value H at the point of support, which is given by Eq. (52), where D is the calculated sag from 3.2.

$$H = H_1 + (W_0 + W_{ice}) \cdot D \quad [N] \tag{52}$$

  The longitudinal force along the axis of the line includes the horizontal tension and the deflection angle of the structure. This is calculated according to Eq. (53), where the longitudinal projection of conductor tension is considered, while the wind component is neglected assuming that wind blows only perpendicular to the line axis [20].

$$F^l = H \cdot cos(\frac{\alpha}{2}) \tag{53}$$

  Transverse forces are perpendicular to the line axis, in the horizontal plane, caused by wind and/or angles in the line corridor as shown in Figure 14.

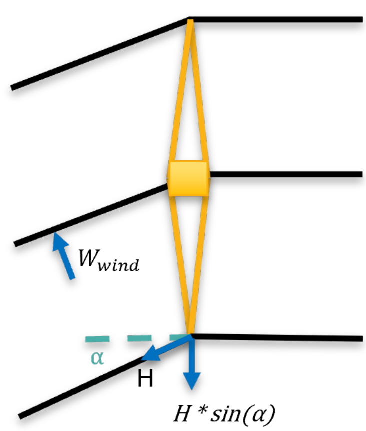

Figure 14: Transverse forces on angled structures

  The force component from the angle is given in Eq. (54). When the wind blows on the conductor, the induced transverse force on the structure is expressed in Eq. (55), where S^h is the horizontal-span (or wind-span) defined as half of the sum of two adjacent spans.

$$F^\alpha = H \cdot sin(\frac{\alpha}{2}) \tag{54}$$

$$F^{wind} = W_{wind} \cdot S^h \cdot cos(\frac{\alpha}{2}) \tag{55}$$

Then the transverse force is calculated as the sum of F^{α} and F^{wind} (Eq. (56).

$$F^t = F^{\alpha} + F^{wind} \tag{56}$$

The total horizontal force F is calculated as the magnitude of the vector sum of the longitudinal and transverse forces as given in (57), where N is the total number of conductors (considering all phases/poles and circuits).

$$F = \sqrt{(F^t)^2 + (F^l)^2} \cdot N^{ckt} \cdot N \qquad [N] \tag{57}$$

This total force F is currently calculated for the angled deadend structures, which need more strength compared to other structure types.

- Check the database of structure types to select the structure with a strength F^s able to support the loading force F by satisfying Eq. (58), where ld is the loading safety factor and sf is the strength factor (both specified in common codes, e.g NESC, California G.O. 95, RUS etc.). A database of structures with their loading strength is constructed from [20, 21], and [22].

$$ld \cdot F \leq sf \cdot F^s \tag{58}$$

- Suggest for each conductor in the "Results" section the smallest structure which satisfies mechanical loading requirements (A database of structures with their loading strength is constructed from publicly available data).

6.1 Implementation in the REFA Tool

- The user is able to specify the composition of structure types and their heights. This is added as an optional feature that the user can activate/deactivate.
- Mechanical loading calculations are conducted for all feasible conductors (based on ampacity, sag, and corona effect). The obtained loading force F is used to select the smallest (least-cost) structure which satisfies the mechanical loading requirement from a collected database of typical structures.
- The suggested structure type for each feasible conductor is appended to conductor results in the new tab "Additional Results".

7 Corona Effect

Corona inception field is the maximum electric field strength that can exist around a conductor before a corona discharge occurs. The electric field strength at the conductor surface at stable corona inception depends on the conductor geometry/material, voltage level, pollution, aging, and atmospheric/weather conditions. The voltage at which the corona inception field produces a discharge is called the inception voltage, given in (59) using Peek's empirical formula [23].

$$V^c = \frac{29.8}{\sqrt{2}} \cdot m_c \cdot \delta \cdot m_t \cdot r \cdot N^{cd} \cdot \ln\left(\frac{GMD}{r}\right) \tag{59}$$

$$\delta = p_{atm} \cdot \left(\frac{293}{273 + T}\right) \cdot e^{-0.00012 \cdot h} \tag{60}$$

where
V^c is the inception voltage [kV],
m_c is the rugosity coefficient of the conductor (1 for polished conductors, 0.92-0.98 for dirty conductors, and

0.8-0.87 for stranded conductors),
δ is the air correction factor (calculated according to (60) with p_{atm} being the pressure in atm, T the temperature in °C, h the altitude in meters),
m_t is the weather correction factor (considered as 0.8 for rainy conditions),
r is the conductor's radius in centimeter cm,
GMD is the geometrical mean distance between phases according to equation (62) or (66) depending on the design of the line.
N^{cd} is the number of conductors in the bundle.

For a specific structure that the user is free to select, phase separation and the number of conductors per phase are specified for corona effect calculations (in addition to the weather correction factor and the rigosity coefficient) as illustrated in Figure 15.

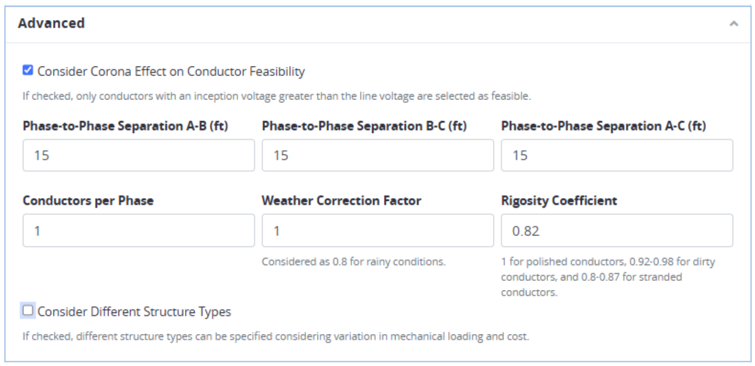

Figure 15: Setting parameters for corona effect calculations

A corona discharge occurs when the line operating voltage V exceeds the inception voltage V^c, a corona discharge occurs, which yields a power loss $P^{ls,c}$ computed as in (61), where f is the frequency of the system.

$$P^{ls,c} = \frac{241}{\delta} \cdot (f + 25) \cdot \sqrt{\frac{r}{GMD}} \cdot \left(\frac{V - V^c}{\sqrt{3}}\right)^2 \cdot 10^{-5} \tag{61}$$

7.1 Geometrical Mean Distance (GMD)

The geometrical mean distance (GMD) is the equivalent distance between the conductor bundles of an overhead line. Distances between different phases are defined as D_{ab}, D_{ac}, and D_{bc}. For a one circuit line, the GMD is given in equation (62).

$$GMD = \sqrt[3]{D_{ab} \cdot D_{ac} \cdot D_{bc}} \tag{62}$$

In case of a two circuits line (a circuit at each side of the structure), with a simple configuration where phases abc are placed from top to bottom in the left, and a'b'c' in the right, the GMD is calculated using equations (64)−(66).

$$D_{AB} = \sqrt[4]{D_{ab} \cdot D_{ab'} \cdot D_{a'b} \cdot D_{a'b'}} \tag{63}$$

$$D_{BC} = \sqrt[4]{D_{bc} \cdot D_{bc'} \cdot D_{b'c} \cdot D_{b'c'}} \tag{64}$$

$$D_{CA} = \sqrt[4]{D_{ca} \cdot D_{ca'} \cdot D_{c'a} \cdot D_{c'a'}} \tag{65}$$

$$GMD = \sqrt[3]{D_{AB} \cdot D_{BC} \cdot D_{CA}} \tag{66}$$

An average GMD over the entire overhead line (OHL) can be calculated considering span lengths as weights as given in (67), where S_i is the length of span i and S^{ohl} the length of all the spans in the overhead line.

$$GMD^{ohl} = \frac{\sum_{i=1}^{spans} (GMD_i \cdot S_i)}{S^{ohl}} \tag{67}$$

7.2 Implementation in the REFA Tool

- This feature can be activated/deactivated from "Advanced" tab, where new parameters are added: the number of conductors per phase N^{cd} (or per DC pole), the spacing between phases (or DC poles), the weather correction factor, and the rugosity coefficient.
- The corona effect calculations are inserted to the constraint-checking phase of the tool, i.e. just after getting the feasible conductors based on ampacity and sag.
- A new tab is added to the "Results" section named "Additional Results", showing the level of corona inception voltage for each feasible conductor (similar to "Current" and "Sag" tabs), alongside suggested structures.
- The cost of corona loss is calculated for the existing conductor similar to Eq. (30) by multiplying the corona loss power $P^{ls,c}$ in Eq. (61) by the energy cost and the loss of load factor.